CHAPTER 1—ENERGY

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Regulations on the Construction, Location, Ownership, and Operation of Ocean Thermal Energy Conversion (OTEC) Facilities and Plantships (15 CFR Part 1001)

Legal Authority

Ocean Thermal Energy Conversion Act of 1980, 42 U.S.C. § 9101 *et seq.*

Reason for Including This Entry

These regulations are of significant public interest and may create a major impact on the economy by providing a new legal system under which various commercial Ocean Thermal Energy Conversion (OTEC) operations may proceed.

Statement of Problem

OTEC facilities and plantships (a plantship is basically an OTEC facility that floats unmoored or moves through the water) will produce electric power from the thermal differential between warm ocean surface waters and cold, deep (approximately 1,000 meters) waters. The electricity generated could be fed ashore by cable and distributed via normal electric distribution grids, or it could be used at sea to produce ammonia or other chemical or metallurgical products. The industry is in a formative stage at present, because although the basic principles of OTEC power generation have been tested, the hardware, engineering, and operational requirements of commercial-scale OTEC operations are yet to be developed and will require very substantial capital investments of tens or hundreds of millions of dollars.

Several U.S. shipyards, engineering firms, makers of electrical generating equipment, and electricity and ammonia suppliers have expressed significant interest in building and operating demonstration-scale and commercial-scale OTEC facilities. The U.S. national interest in OTEC grows out of its potential as an alternative (non-fossil fuel, non-nuclear) energy source. The U.S. House of Representatives' Committee on Merchant Marine and Fisheries, Subcommittee on Oceanography, estimates that OTEC could produce as much as 10 percent of the U.S. electrical generating capacity by the year 2000, and up to 25 percent of all new electrical generating capacity coming on-line between now and the year 2000, if the OTEC program is successful and aggressively pursued (see House Report No. 96–944, at page 25). The OTEC principle can be applied most economically in areas where the thermal differential between surface and deep waters is about 20° C or more; this constraint dictates that U.S. use of OTECs will be limited to the Gulf of Mexico and the southeastern United States and to U.S. island areas such as Hawaii, Puerto Rico, the U.S. Virgin Islands, and the U.S. Western Pacific islands.

These proposed regulations will implement the Ocean Thermal Energy Conversion Act of 1980 (the Act), which authorizes the Administrator of NOAA to license (and requires persons to obtain licenses prior to) the construction, location, ownership, and operation of: (1) OTEC facilities connected to the United States by pipeline or cable; (2) OTEC facilities located in the territorial sea of the U.S.; (3) OTEC plantships documented under the laws of the United States; and (4) OTEC plantships that are constructed, owned or operated by U.S. citizens.

The Act requires NOAA to issue regulations with respect to licensing of these OTEC facilities and plantships.

Along with its licensing provisions, the Act is intended to: (1) establish a legal system to encourage the development of OTEC as a commercial energy technology; (2) protect the marine and coastal environment and the interests of other users of the territorial sea, Continental Shelf, and high seas, and foreign nations that may be affected by a thermal plume (heated discharge) from an OTEC; and (3) ensure that

Federal OTEC-related actions are consistent with approved State coastal zone management plans. The Act requires NOAA to issue final implementing regulations by August 3, 1981.

Alternatives Under Consideration

NOAA is just beginning its rulemaking process to implement the Act. The Agency has only begun to identify issues that we could treat in alternative ways. In developing these OTEC regulations, NOAA will address issues which may fall in several broad areas, including: (1) the amount and type of financial, technical, environmental, and other information that an applicant must submit with an application; (2) criteria for selecting OTEC projects when there are multiple applicants for the same geographic area; (3) environmental safeguards; (4) environmental monitoring requirements; and (5) the prevention of interference by one OTEC facility or plantship with another, and with other users of the territorial sea, Continental Shelf, and high seas.

In identifying and evaluating alternatives for the development of OTEC regulations for each of these general areas, NOAA first would define the basic objectives for each, and then evaluate alternative approaches. Three general approaches are for NOAA to:

(A) Address these areas in substantial detail in its regulations, providing specific terms that would apply to all OTEC operations. If experience later revealed that such degree of detail and extent of requirements were unnecessary, we could reduce them.

(B) Address an area in a more general way in its regulations, and then apply the concepts in those regulations to the specific facts and site characteristics associated with each license or permit, relying more on individual terms, conditions, and restrictions for detail.

(C) Employ less detailed requirements in both the regulations and the terms, conditions, and restrictions for each OTEC license, and rely on the subsequent monitoring specified in the Act to ascertain whether additional requirements were needed in the future.

In considering alternative approaches to these regulations, NOAA will assess the feasibility of relying on certain innovative techniques which may allow more flexibility for OTEC builders, owners, or operators while still accomplishing the purposes and requirements of the Act. For instance, NOAA may be able to rely on general environmental performance standards or parameters, rather than specifying detailed requirements concerning use of specified types or models of equipment or specified operating procedures. NOAA also may provide generalized guidance in its regulations for meeting the requirements of the Act, but then make it the responsibility of the applicant to specify in detail in its application how it will meet these requirements. Once we issued a license, we would expect the OTEC builder, owner, or operator to conduct its activities according to the terms of its application. NOAA will consider impacts on small business from the regulations.

Summary of Benefits

Sectors Affected: Ocean thermal energy production; ship-building and repairing; manufacturing of electric transmission and distribution equipment and electric industrial apparatus; electric utilities; production of ammonia, fertilizer, aluminum, and other energy intensive products; inhabitants of the U.S. southeastern and Gulf of Mexico states, the U.S. Virgin Islands, Puerto Rico, Hawaii, and the U.S. Pacific island possessions and territories; and the general public.

Commercialization of the OTEC technology under the new legal system of the Ocean Thermal Energy Conversion Act and the proposed regulations could generate benefits to the ship-building and repairing industry that would construct and maintain the OTEC facilities and plantships. Electrical equipment manufacturers would benefit from any additional demand for electric generation and transmission equipment. Energy intensive industries such as production of ammonia, some fertilizers, and aluminum would benefit from availability of a competitively priced alternative source of electric power. Areas of the United States adjacent to ocean waters which contain thermal differentials sufficient to support OTEC power generation would benefit from availability of a non-fossil, non-nuclear energy supply and consequent reduction of costs or risks associated with fossil or nuclear fuel. The regulations will provide the framework for development of a new OTEC industry, which will benefit those owning and operating OTEC facilities or plantships as a business. The Regulatory Analysis which NOAA will prepare on these regulations will quantify these benefits.

Summary of Costs

Sectors Affected: Suppliers of fossil and nuclear fuel for electric power production; suppliers of natural gas for production of ammonia, fertilizer, aluminum, and other energy intensive products; construction of land-based electric power plants; inhabitants of the U.S. southeastern and Gulf of Mexico states, the U.S. Virgin Islands, Puerto Rico, Hawaii, and the U.S. Pacific Island possessions and territories; and ocean thermal energy production.

Some companies whose business is based on supplying fossil or nuclear fuel for electric power production may lose market opportunities to the extent OTEC facilities or plantships are built on a commercial scale and replace other sources of energy. Suppliers of natural gas feedstocks for production of ammonia and other energy intensive products would suffer some market displacement as OTEC power becomes available for ammonia production from air and seawater. To the extent that availability of OTEC electric power in affected areas of the U.S. results in economic development which causes environmental or socioeconomic problems, some costs may be incurred in the areas where OTECs operate. Persons applying to construct, own or operate OTEC facilities or plantships will incur costs in assembling the financial, technical, environmental, and other information required for the license application, and in complying with license conditions relating to matters such as environmental protection and monitoring and non-interference with other users of the ocean. The Regulatory Analysis will address these costs in more detail.

Related Regulations and Actions

Internal: None.

External: Under the Act, the Coast Guard must issue regulations governing documentation, design, construction, alteration, equipment, maintenance, repair, inspection, certification, and manning of OTEC facilities and plantships. The Coast Guard also is to issue, after consulting with the Administrator of NOAA, regulations governing the movement and navigation of OTEC plantships to insure that the thermal plume from the plantship generally does not unreasonably impinge upon and degrade the thermal gradient (the net temperature differential between warm surface waters and cold deep waters) of another OTEC facility or plantship, or adversely affect the territorial sea or natural resource jurisdiction zone of a foreign nation. NOAA also must consult the Coast Guard before deciding whether to issue regulations governing site evaluation and preconstruction activities. NOAA and the Coast Guard may "jointly or severally" issue enforcement regulations. The

Environmental Protection Agency may prepare regulations applicable to OTEC facilities and plantships under the National Pollutant Discharge Elimination System program under the Clean Water Act. The Secretary of Energy may determine, after consultation with the Administrator of NOAA, which substantive requirements of Title I of the Act will apply to OTEC demonstration projects. NOAA must consult with "the Secretary of Energy and the heads of other Federal agencies" before issuing regulations to carry out the Act.

Active Government Collaboration

NOAA already has initiated discussions with the Department of Energy, the Maritime Administration, the Coast Guard, and the Environmental Protection Agency concerning implementation of the Act and the respective programs and jurisdictions of the other agencies. NOAA also will discuss matters with the Departments of State (with respect to non-interference with other ocean users, and with other nations) and Justice (with respect to OTEC antitrust issues). NOAA also intends to initiate discussions with components of the Department of the Interior, such as the U.S. Geological Survey and the Bureau of Land Management, in order to benefit from their experience in certain areas where those agencies have faced similar issues. Furthermore, NOAA intends to coordinate with the Small Business Administration in order to assess the potential impact of these regulations on small businesses.

In addition to this coordination with affected Federal agencies, NOAA will contact relevant State (and, as appropriate, local) government officials in potentially affected areas (for example, the Gulf of Mexico area, the U.S. Virgin Islands, Puerto Rico, Hawaii, and the Commonwealth of the Northern Mariana Islands).

Timetable

ANPRM—NOAA may publish one in November/December 1980.
NPRM—March 1981.
Regulatory or Other Analysis—NOAA plans to issue a draft Regulatory Analysis and a draft Environmental Impact Statement (EIS) in March 1981.
Public Hearing—NOAA plans to hold at least one public hearing on the proposed rules and accompanying draft EIS after NOAA issues the NPRM and draft EIS. In addition, NOAA intends to hold public meetings concerning the proposed rules and the draft EIS before issuing those documents.
Public Comment Period—A 60-day public comment period will follow the NPRM.
Final Rule—July 1981.
Final Rule Effective—August 1981.

Available Documents

A Federal Register notice requesting other Federal agencies having expertise concerning, or jurisdiction over, any aspect of the construction or operation of OTEC facilities and plantships to send NOAA written descriptions of their expertise or statutory responsibilities (45 FR 56857, August 26, 1980).

Notice of Environmental Impact Statement (EIS) scoping meeting (45 FR 63543, September 25, 1980).

As other documents pertaining to this rulemaking and development of the EIS become publicly available, they may be obtained from the Office of Ocean Minerals and Energy, NOAA, Page Building No. 1, Room 410, 2001 Wisconsin Ave. NW., Washington, DC 20235 (Telephone: (202) 653–7695).

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DEPARTMENT OF ENERGY

Conservation and Solar Applications

Commercial and Apartment Conservation Service Program (10 CFR 458 *)

Legal Authority

National Energy Conservation Policy Act (NECPA), P.L. 95–619, 92 Stat. 3206; Energy Security Act (ESA), P.L. 96–294, 794 Stat. 611.

Reason for Including This Entry

The Department of Energy (DOE) believes this rulemaking is important because it will expand the Commercial and Apartment Conservation Service (CACS) program, which now encourages the installation of energy-saving measures and the adoption of energy conserving operation and maintenance practices in small multifamily dwellings. Our rule would expand the CACS program to also cover existing small commercial buildings and large (five or more units) multifamily dwellings. We estimate that the rule will result in savings of 136 million barrels of oil equivalent through the year 2000.

Statement of Problem

The residential and commercial building sectors consume about 38 percent of the Nation's total energy use. In the residential sector, 90 percent of energy usage occurs in single-family homes and multifamily dwellings with less than five units. Promotion of conservation efforts within this sector is covered in the rules adopted by DOE in November 1979, the Residential Conservation Service (RCS) program (part 1, Title II of NECPA). RCS requires approximately 350 larger gas and electric utilities to provide information on energy conservation practices and measures appropriate by building type to their residential customers in one- to four-unit dwellings. RCS also requires covered utilities to offer such customers the opportunity to request various services, including an on-site audit; assistance in arranging for the purchase and installation of recommended conservation and renewable resource measures; lists of suppliers, lenders, and contractors agreeing to conform to RCS Standards and program requirements; the opportunity to include the costs of such installations in monthly utility bills; written one-year manufacturers' and installers' warranties; and access to consumer grievance procedures.

The remaining 10 percent of the energy used by the residential sector is in multifamily dwellings of five or more units, representing 15 percent of the residential sector. Energy saving incentives traditionally have been fewer for residents in such buildings, especially in units which are master metered. In order to help meet the President's buildings weatherization goals by 1999 as contained in the National Energy Plan II, DOE is proposing this rulemaking to cover both multifamily buildings of five or more units and that portion of the commercial sector containing buildings that use less than 1,000 therms of natural gas, 4,000 kilowatt hours of electricity per month, or combined energy usage of all fuels that is less than the equivalent of 114 million Btu's.

Under both the RCS program and its expansion through CACS in the proposed rulemaking, DOE invites States to submit plans to DOE for approval to administer and enforce utility compliance with State programs. According to § 211 of NECPA, utilities covered by RCS and CACS included all those which during the second preceding year had sales (for purposes other than resale) which 1) exceeded 10 billion cubic feet for natural gas, or 2) exceeded 750 million kilowatt hours of electricity. Participating Governors must decide

whether or not to include non-regulated, municipally owned utilities and interested home heating suppliers in State plans. Non-regulated utilities not included in State plans but meeting the above size criteria must prepare and submit their own plans for DOE approval. NECPA requires DOE to prepare a Federal plan and order covered investor owned utilities to comply with it in cases where no approved State plan exists; in such circumstances non-regulated utilities will prepare and submit plans.

The energy use in the sectors covered by this rulemaking, while smaller than that of single-family homes, is nonetheless very significant in that it represents 30 percent of the energy equivalent of U.S. oil imports. Numerous studies by DOE and others have demonstrated that a major fraction of this energy use could be eliminated by cost effective investments in retrofitting of existing buildings. DOE's objective through the CACS program is to aid small business and apartment owners and tenants to achieve cost-effective energy savings. DOE recognizes that appropriate energy saving information is costly to obtain, and there is much inertia on the part of small business personnel to spend the time and resources needed to secure and analyze such information. Therefore, the Government will play a useful role in requiring covered utilities (and home heating suppliers willing to participate) to make appropriate information available to owners and tenants of applicable buildings.

Unlike RCS, the CACS program is principally an information program, and participation is voluntary for building owners and tenants. The proposed program does not mandate specific actions to save energy except to the extent that it stimulates owners and tenants of commercial and apartment buildings to request the audit and adopt conservation practices and install conservation and renewable resource measures. The success of the program depends largely on the enthusiasm with which covered utilities carry out the intent of the program to encourage customers to both respond to the offer of on-site audits and actually make energy-saving improvements in buildings.

Alternatives Under Consideration

The statute sets specific criteria for expansion of RCS to the commercial building and multifamily dwelling sectors and requires the Secretary to develop regulations to carry out the program. The highly prescriptive nature of the statute leaves relatively little discretion to the Secretary in developing this proposed rulemaking. However, in some instances, elements of this rulemaking that differ from the RCS regulations are indicative of the choice of alternatives.

In contrast to RCS, the proposed rulemaking requires covered utilities to provide a building energy use monitoring list to building managers and a Tenant's Energy Conservation Information Package to commercial and apartment building tenants once an audit has been requested. The audit requirements in the proposed rulemaking differ from RCS due to the differences in buildings. Unlike the one- to four-unit residential units covered by RCS, commercial and apartment buildings covered by CACS vary substantially in size, structure, and energy use. Owners of such buildings are mostly business persons, and the measures appropriate to the various structures are diverse, with equipment types varying widely in each category. As a result of these differences, the proposed regulations allow much greater latitude to States and utilities; require utilities to provide fewer services to eligible customers; and include a greater use of estimates based on typical values achieved in similar facilities than do the RCS regulations.

Summary of Benefits

Sectors Affected: Federal Government; State governments; investor-owned and municipally owned electric and gas utilities meeting the sales criteria established in § 211 of NECPA; participating home heating oil suppliers; tenants and owners of eligible commercial buildings and multifamily dwellings of five or more units; and the general public.

All sectors affected will benefit from the energy savings achieved by the program. The Federal Government will benefit from having limited sources of non-renewable fuels extended by the conservation actions of building owners and tenants. DOE estimates that total energy savings resulting from the proposed regulation will be 136 million barrels of oil equivalent through the sectors covered through the year 2000. Building owners' and tenants' benefits will be realized in terms of lower or controlled utility bills and greater personal comfort. Utilities will benefit by avoiding additional capital expenditures for increased generating capacity. Home heating suppliers will preserve good customer relations and may expand their base of operations as a result.

Summary of Costs

Sectors Affected: Federal Government; State governments; investor-owned and municipally owned electric and gas utilities covered by the regulations; participating home heating oil suppliers; tenants and owners of eligible commercial buildings and multifamily dwellings of five or more units; and the general public.

Total cost of the programs are estimated at $1,026 million (1980 dollars) for the multifamily sector and $770 million for the commercial sector. The cost of energy saved on a discounted basis is $11.50 per barrel of oil equivalent for the multifamily sector and $7.89 for the commercial sector. The cost of developing, implementing, and monitoring the proposed CACS program to 1990 is expected to be $16 million. State governments will encounter costs for similar activities, including State plan development, implementation, and enforcement. The costs are considerably less than for the same responsibilities under RCS. It is expected that the test cost to States to the year 1990 will be $52.5 million. Covered utilities will be able to charge eligible customers up to $15 per dwelling unit for providing the prescribed on-site audit. The method to recover the remainder of such costs will be determined by the rate-making authority in the case of investor-owned utilities and by the utility directly in the case of non-regulated utilities. The statute requires that the utility take into account the customer's ability to pay in determining charges. DOE estimates that the total program costs to utilities to the year 1990 will be $251.7 million (1980 dollars), while the projected cost to building tenants and owners for the audit and selected building modifications will be $705.9 million. It should be stressed that the program is entirely voluntary for eligible building owners and tenants.

Related Regulations and Actions

Internal: DOE has or is cooperating in several on-going programs which also provide energy conservation assistance to homeowners. These programs include (1) existing RCS program for single-family residences, (2) Low-Income Weatherization Assistance Program, (3) Energy Extension Service, and (4) State Energy Conservation Grant Program.

External: Existing State laws or regulations.

Active Government Collaboration

DOE will work closely with interested States to prepare, implement, and monitor State Plans for this program.

Timetable

NPRM—November 1980.
Final Rule—March 1981.
Regulatory Analysis—Being prepared.

Available Documents

None.

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DOE–CS

Emergency Building Temperature Restrictions (10 CFR Part 490)

Legal Authority

The Energy Policy and Conservation Act, §§ 201(a) and (b), 42 U.S.C. § 6261(b) *et seq.*

Reason for Including This Entry

This entry is included because of its widespread impact on the non-residential building sector and its importance as a nationwide mandatory conservation measure.

Statement of Problem

The Emergency Building Temperature Restrictions (EBTR) were implemented July 16, 1979, after the President determined that the United States was unable to rely upon imports of crude oil to meet normal demand due to international instability. Worldwide production of crude oil is now at levels below those of the comparable period last year. As the President pointed out in the proclamation extending the Building Temperature Restrictions on April 15, 1980, the United States has had to terminate crude oil imports from Iran and is experiencing increased uncertainty about the level of continued crude oil supplies from other producing countries. Actions by the Soviet Union in Afghanistan and the tensions between Iraq and Iran further increase the threat to the stability of commerce in the Persian Gulf.

United States dependence on insecure crude oil imports, which have rapidly increased in price, has substantially increased our inflation rate and created a major adverse impact on the national economy. Because these effects are likely to be of significant scope and duration, it is necessary to take action which will help forestall additional shortages.

The Energy Policy and Conservation Act (EPCA) contains provisions permitting the President to develop and submit to Congress standby emergency energy conservation contingency plans. Standby Conservation Plan No. 2, Emergency Building Temperature Restrictions, was transmitted to Congress on March 1, 1979, and approved by both Houses. The plan was implemented by Presidential proclamation on July 16, 1979, due to a severe energy supply disruption caused by events in Iran, and renewed for an additional 9 months on April 15, 1980.

Savings are estimated between 200,000 to 400,000 barrels per day oil equivalent, about 25 percent of which can be translated directly into barrels of oil saved, principally middle distillates. By saving this amount of energy, EBTR may help to alleviate the severity of the continuing energy crisis faced by the Nation. Additionally, EBTR has helped complying building owners and operators to develop new energy-saving modes of building operation.

EBTR accomplishes this goal by generally requiring that thermostats in most nonresidential buildings be set no lower than 78° F. for cooling, no higher than 65° F. for heating, and no higher than 105° F. for general purpose hot water. The regulations also require building temperature setbacks during unoccupied hours.

Alternatives Under Consideration

The EBTR regulations permit any State or political subdivision to submit to the Department of Energy (DOE) for approval a comparable plan which could include temperature limits other than those provided for in the EBTR regulations, in addition to other building energy conservation measures. Such plans have already been approved for New Jersey, Massachusetts, and Houston, Texas.

Section 231 of Title II of the Emergency Energy Conservation Act of 1979 (EECA) (P.L. 96–102, 93 Stat. 757, to be codified at 42 U.S.C. 8501) requires that EBTR must permit a State or political subdivision to include in any comparable plans procedures permitting individual building owners to propose alternative conservation means that will achieve at least as much energy savings in their buildings as would the temperature restrictions plan. DOE has published an amendment to the EBTR regulations bringing them into compliance with this provision of EECA (10 CFR Part 490).

DOE is also considering publication of an amendment which would permit all building owners or operators to comply with the regulations through alternate plans which would conserve as much energy as would adherence to the temperature restrictions alone. Alternate means would not be restricted to adjustments in heating, ventilating and air-conditioning systems, but might include any changes in the design, construction, or operation of the building such as lighting reduction, insulation, weatherstripping, installation of control systems, hours of operation, etc. This will afford maximum flexibility to building owners and operators and give retailers, restauranteurs, and others the chance to implement strategies which they have indicated may be more appropriate to their particular circumstances. This amendement would be designed to help foster creative and innovative approaches to energy-efficient building operation. Administration of the program would, however, grow more complex and costly, and the alternate plan approach may not be appropriate to short-term emergency implementation of the EBTR regulations as they now exist.

The emphasis of the EBTR program is on voluntary public compliance. Although over 40,000 building inspections have been conducted by DOE and participating States (demonstrating approximately an 80 percent compliance rate), inspectors have concerned themselves primarily with educating the public and assisting building owners in bringing their buildings into compliance, rather than stressing enforcement and punitive action.

Summary of Benefits

Sectors Affected: The general public; and owners, operators, and users of approximately 2.8 million nonresidential buildings, including industrial/manufacturing buildings, schools, restaurants, retail stores, offices, hotel/lodging nonsleeping areas, shopping centers, warehouses, and retail food stores, and excluding the sleeping areas of hotels and other lodging facilities, health care facilities, elementary schools, nursery schools, and day care centers.

Compliance with the EBTR regulations can save an average of 6 percent of total building energy use (with consequent reductions in utility bills), although this figure will naturally vary from building to building.

In estimating potential fuel savings, computer simulations of building energy usage before and after EBTR were used. These building models were based on sensitivity analyses of key characteristics affecting energy savings.

such as infiltration and building HVAC (heating, ventilating, air-conditioning) system type. Building owners and managers will become more conscious of energy conservation.

Summary of Costs

Sectors Affected: DOE; and State energy offices.

The costs of EBTR are primarily administrative. Eight million dollars were expended over the first 9 months of the program to cover grants to States for inspections and public education, and DOE regional and headquarters support. This included funding for program analysis, administrative costs, printing and mailing of program manuals, and operation of a toll-free EBTR information hotline.

Related Regulations and Actions

Internal: The Standby Federal Emergency Energy Conservation Plan (10 CFR Part 477, February 7, 1980) developed under the authority of EECA, contains a building temperature measure similar to EBTR.

External: Some State energy offices are considering the inclusion of building temperature measures in State emergency energy conservation plans being developed to meet the requirements of EECA.

Active Government Collaboration

DOE has been working with over 75 Federal agencies to ensure that all Federal buildings are in compliance with EBTR. The energy conservation directors of each of these agencies have maintained contact with DOE and have inspected any buildings against which public complaints have been lodged. The General Services Administration, Department of Defense, and U.S. Post Office, the three Federal agencies with the largest building populations, are in almost daily contact with DOE regarding EBTR enforcement within their jurisdictions. DOE, with over 122,000 buildings covered by EBTR, has conducted inspections of 64,000 buildings since the program was implemented in July 1979.

Timetable

Final Rule—November 1980.

Available Documents

NPRM—45 FR 35788, May 27, 1980.

Emergency Building Temperature Restrictions Regulations, 10 CFR Part 490, July 5, 1979.

"How to Compy with Emergency Building Temperature Restrictions." Copies may be obtained by writing to the Agency Contact listed below or calling the toll-free Emergency Conservation Service Hotline: (800) 424-9122 or 252-4950 (Washington, DC).

Emergency Building Temperature Restrictions Docket No. CAS-RM-79-109. Transcripts of all public hearings and supporting documents are available for review in the Freedom of Information Office. Correspondence should be addressed to: Milton Jordan, Director, Freedom of Information Office, Department of Energy, 1000 Independence Avenue, S.W., Room 5B-138, Washington, DC 20585.

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DOE-CS

Energy Conservation Program for Consumer Products Other Than Automobiles (10 CFR Part 430*)

Legal Authority

Energy Policy and Conservation Act, Title III, Part B P.L. 94-163, 89 Stat. 917, as amended by the National Energy Conservation Policy Act, P.L. 95-619, 92 Stat. 3257.

Reason for Including This Entry

The Department of Energy (DOE) includes this entry because the proposed rule imposes substantial costs on the home appliance industry, increases the cost of appliances, and involves energy conservation issues of great public interest.

Statement of Problem

Major consumer products now being manufactured are less energy efficient than they could be. DOE's Conservation Program for Consumer Products Other Than Automobiles seeks to reduce energy consumption of major household consumer products. The legal authority establishes 13 product categories for review. These product categories are: refrigerators and refrigerator/freezers, dishwashers, clothes dryers, water heaters, room air conditioners, home heating equipment (not including furnaces), television sets, kitchen ranges and ovens, clothes washers, humidifiers and dehumidifiers, central air conditioners, and furnaces.

The legal authority also allows for a 14th product category for any other type of consumer product classified as a covered product in accordance with § 322(b) of the Act.

DOE has developed test procedures measuring efficiency levels of products covered by the proposed energy efficiency standards. These standards will establish the minimum level of energy efficiency that the manufacturer of the covered product must achieve, but will not prescribe the methods, designs, processes, or materials to be used to achieve the particular efficiency level. The Energy Policy and Conservation Act (EPCA) further directs that DOE design any standard it issues to achieve the maximum improvement in energy efficiency which is technologically feasible and economically justified. Manufacturers will be required to certify that their products are on conformance with the standards by testing them in accordance with DOE test procedures before they can place such products on the market.

Alternatives Under Consideration

The major alternatives considered for each covered product were labeling, rebates, tax incentives, consumer education, prescriptive standards, voluntary programs, and no regulation.

Each of these alternatives has been evaluated relative to achieving the mandate of Congress, and other related policy objectives.

We considered the alternative of labeling as the primary action of DOE to be inappropriate because Congress has, in the Act, mandated the establishment of a labeling program by the Federal Trade Commission (FTC). FTC's labeling program requires that eight of the 13 covered products be labeled to reflect average annual operating costs or energy efficiency ratings. These costs are based on Federal test procedures developed by DOE.

We determined that the alternative of providing consumer rebates for purchase of more energy efficient products would involve unnecessary expenditure of Federal funds. Since the consumer is the ultimate benefactor with regard to net cost savings resulting from increased energy efficiency, a rebate to the consumer would serve only to further increase the consumer's economic benefit. In addition, a rebate would be provided to consumers who would have purchased more efficient products without further stimulus as well as to those whose behavior would be altered by the incentive. The length of time over which the rebate would be extended was also a factor in rejecting this alternative. A long-term program could be very costly, while a short-term program may not achieve lasting benefits.

DOE also considered the alternative of providing tax incentives for purchasing or manufacturing energy efficient products. Many of the same problems that we anticipated in the rebate alternative are also pertinent to this alternative. In both programs, the majority of the associated costs would be borne by the Federal Government, i.e., distributed among all taxpayers, while the benefits would be derived only by the purchasers of covered products. Thus, on an individual-by-individual basis, the costs would outweight the benefits for those taxpayers who do not purchase the covered products.

DOE has not rejected the alternative of a consumer or public education program. Rather, DOE believes that a strong, viable education program is an important facet of any approach undertaken to achieve energy efficiency of the covered products. DOE's education program will focus on educating consumers to read energy efficiency labels when purchasing covered products, and on the most energy efficient use of the covered products. The concept of energy efficiency does not only relate to the design of a product, but also to how the product is used. The benefits of a well-designed energy efficient product may be completely lost if users are not aware of how to operate and maintain the product to achieve the desired performance. For example, some refrigerators provide an antisweat heater to use during damp or humid weather. Proper use of the heater will reduce energy consumption of the refrigerator.

Other alternatives that DOE considered include the possibility of prescriptive standards based on specific energy efficient design elements rather than the proposed performance standards. We rejected this approach because of the potential for reducing manufacturers' options to use innovative technology to achieve the energy efficiency requirements.

The original version of the Act (EPCA, P.L. 94-163) called for the industry to set up voluntary energy efficiency targets for the covered products. Congress specifically changed this section when amending the Act to provide for immediate establishment of Federal standards. DOE rejected the voluntary program in order to achieve energy efficient products as rapidly as possible.

The "no regulation" alternative assumes that standards are not implemented for any of the covered products. If DOE chooses this alternative, some energy efficiency improvements would result in the covered products because of State regulations, and labeling programs, voluntary industry certification, and increasing interest by consumers in energy efficiency as energy costs rise. However, these increases would be much less than the levels that would be obtained with minimum energy efficiency standards. Thus, relative to the proposed standards, this alternative would result in smaller energy savings and reduced progress toward national energy self-sulficiency.

DOE proposes to require industry to meet a prescribed performance standard rather than a specific design standard, leaving the manufacturer free to find the most cost effective means of compliance while maintaining the desired level of overall quality.

Summary of Benefits

Sectors Affected: Manufacturers and users of major household appliances; and the general public.

The improvement of consumer product efficiencies will decrease the amount consumers pay on their monthly utility bills and the overall amount of energy consumed in the Nation. We also expect that implementation of Federal standards will accelerate adoption of high efficiency consumer products by 10 years. Standards will be effective beginning in 1981. All products below the prescribed level of standards will be eliminated. Energy savings are estimated at between 13.4 quadrillion, British thermal units (Btu's) and 24.1 quadrillion Btu's over the period 1982 through 2005. The discounted value of these energy savings will be between $18.8 and $24.4 billion, in 1975 dollars. For the year 2000, annual energy savings are expected to be between 0.8 quadrillion Btu's and 1.9 quadrillion Btu's. This translates to energy savings in the range of 376,000 to 993,000 barrels of oil equivalent per day by the year 2000.

Summary of Costs

Sectors Affected: Manufacturing of major household appliances; and users of these appliances.

The costs resulting from implementation of the program will be borne by consumers in the form of increased consumer product prices. This cost over the 1982 through 2005 period is expected to be between $8.3 and $11.1 billion in discounted 1975 dollars. However, the overall program will have a positive net present value between $10.5 and $13.3 billion.

Adverse impacts will be minimized because we will prescribe separate standards for each category of consumer products. This allows the Federal Government to maximize benefits while minimizing burdens in a more judicious manner.

Strong, more technologically sophisticated firms are not expected to be severely burdened. The greatest potential for near-term adverse impacts to manufacturers will be for those which produce air conditioning and refrigeration products. The overall competitive effect of standards is expected to be a slight increase in concentration in this 300 firm industry.

Burdens on manufacturers will be kept to a minimum through careful consideration of potential impacts. In addition, firms with sales under $8 million are allowed exemption from standards for 2 years following promulgation, upon successful petition to the Federal Government.

Related Regulations and Actions

Internal: Energy Performance Standards for New Buildings. Residential Conservation Service Program.

External: Minimum Property Standards for One- and Two-Family Dwellings, Department of Housing and Urban Development.

Federal Trade Commission Appliance Labeling Program.

Active Government Collaboration

Federal Trade Commission and National Bureau of Standards.

Timetable

Final Rule for Nine Products—January 1981.
NPRM for Four Products—March 1981.
Final Rule for Four Products—November 1981.

Available Documents

Draft Regulatory Analysis.
Test Procedures:

Refrigerators, Refrigerator-freezers—42 FR 46140, September 14, 1977.

Freezers—42 FR 46140, September 14, 1977.

Dishwashers—42 FR 39964, August 8, 1977.

Clothes Dryers—42 FR 46140, September 14, 1977; 45 FR 46762, July 10, 1980.

Water Heaters—42 FR 54110, October 4, 1977; 43 FR 48986, October 19, 1978; 44 FR 52632, September 7, 1979.

Room Air Conditioners—42 FR 27896, June 1, 1977; 45 FR 2632, January 11, 1980.

Home Heating Equipment—not including Furnaces, 43 FR 20108, May 10, 1978.

Television Sets—42 FR 46140, September 14, 1977.

Kitchen Ranges and Ovens—42 FR 20106, May 10, 1978.

Clothes Washers—42 FR 49802, September 28, 1977.

Humidifiers and Dehumidifiers—42 FR 55599, October 18, 1977.

Central Air Conditioners, including Heat Pumps—42 FR 60150, November 25, 1977; 44 FR 76700, December 27, 1979.

Furnaces—43 FR 20108, May 10, 1978; 45 FR 53714, August 12, 1980.

NPRM Regarding Provisions for the Waiver of Consumer Product Test Procedures, 45 FR 14188, March 4, 1980.

Sampling Requirements of Consumer Products Test Procedures—44 FR 22410, April 13, 1979.

Public comments (including comments from public hearing held August 1980).

Representative Average Unit Cost of Electricity, Natural Gas, No. 2 Heating Oil, and Propane—44 FR 37534, June 27, 1979.

Standards:

ANPRM Regarding Energy Efficiency Standards for Nine Types of Consumer Products—44 FR 49, January 2, 1979.

ANPRM Regarding Energy Efficiency Standards for Four Types of Consumer Products—44 FR 72276, December 13, 1979.

ANPRM Regarding Energy Efficiency Standards for Heat Pumps—45 FR 5602, January 23, 1980.

NPRM Regarding Energy Efficiency Standards for Nine Types of Consumer Products—45 FR 43976, June 30, 1980.

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DOE-CS

Energy Performance Standards for New Buildings

Legal Authority

Energy Conservation Standards for New Buildings Act of 1976, 42 U.S.C. §§ 6831–6840; Department of Energy Organization Act, § 304, 42 U.S.C. § 7101 *et seq.*

Reason for Including This Entry

This entry is included because it imposes significant costs on the building and residential housing industries, and because it involves energy conservation issues of great public interest.

Statement of Problem

The problem of energy shortages can be addressed by a number of conservation measures. The intent of this regulation is to reduce the amount of energy consumed in new buildings. One-third of all energy consumed in the U.S. is used in buildings. Inefficient building designs and equipment waste about 40 percent of this energy.

The Department of Energy (DOE) is developing design energy consumption budget levels, measured in units of British Thermal Units (Btu's) of design energy consumption per square foot of floor space per year (Btu/sq. ft./yr.). These design energy budgets will take into account the differences in energy consumption required by climate and by different building functions. This regulation will require all new buildings to be designed not to exceed the corresponding energy budget.

Buildings which meet these energy budgets will consume about 45 percent less energy than recently constructed buildings. This will mean aggregate energy savings of 26 quadrillion Btu's through the year 2000, in addition to the other energy saving programs under consideration.

In the NPRM (44 FR 68120, November 28, 1979), Proposed Building Energy Performance Standards are expressed in Btu's per square foot and are multiplied by "weighting factors" to account for the different values of fuels. The measurement of design energy is made using a Standard Evaluation Technique.

Alternatives Under Consideration

(A) Revising the building classification.

(B) Replacing the "Weighting Factors" with dual site budgets.

(C) Adding alternate evaluation techniques to the list of certified evaluation tools.

(D) Adding "certified equivalent energy codes" as an alternative means of complying with the Standard.

Also, an examination of non-regulatory approaches to achieving the Standards has been conducted and is now being refined.

Summary of Benefits

Sectors Affected: The building industry (architectural services, construction, and manufacturing of construction materials); buildings workers (professional, management, skilled, and operative); the building market (realtors, purchasers, and users of buildings); and the general public.

Single family residential buildings designed to comply with the proposed Standards should use between 22 percent and 51 percent less energy than current practice. Commercial and multifamily residential buildings complying with the standards should use between 17 percent and 52 percent less energy. Economic impacts are small, i.e., at a 10 percent real discount rate (which adjusts for the effects of inflation), the Standards may, by 1991, increase the Gross National Product by 0.1 percent, increase employment by 1.0 percent, and improve the balance of trade by 5 percent. The building industry could benefit by increased demand for their services.

Summary of Costs

Sectors Affected: The building industry (architectural services, construction, and manufacturing of construction materials); the building market (realtors, purchasers, and users of buildings); DOE; HUD; and State and local governments.

As a result of the standards, the cost of new commercial buildings is expected to increase about 2.5 percent. The cost of new residential buildings is estimated to increase $.75 to $1.00 per square foot or $1,200 to $1,600 for a 1,600 square foot one-story home. The added cost to enforce the Standards varies with the method used to implement the standards, but assuming State and local governments choose to make existing code mechanisms equivalent, we estimate that the enforcement costs for Federal, State, and local governments will be $55 million.

Related Regulations and Actions

Internal: DOE is developing a Model Building Energy Code which translates the Standards into code language.

External: Minimum Property Standards for One- and Two-Family Dwellings, Department of Housing and Urban Development (HUD); Minimum Property Standards for Multifamily Dwellings; HUD Handbook 4910, Revision 5, April 1977; Proposed Increase in Thermal Insulation Requirements for the Minimum Property Standards for One- and Two-Family Dwellings, 43 FR 17371, April 24, 1978; Farmers Home Administration, Form 424.1; 7 CFR Part 1804, Subpart A, Appendix D, Construction Standards.

Active Government Collaboration

The Department of Housing and Urban Development and National Bureau of Standards are actively involved in the development program.

Timetable

NPRM—August 1981.
Public Comment Period—Will follow

NPRM.

Final Rule—April 1983.

Available Documents

In support of this proposed rule, the Department has developed ten Technical Support Documents. These documents provide detailed information on important aspects of the proposed rule and are referred to throughout the preamble. All documents may be obtained from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22150, and the Technical Information Center, Oakridge National Laboratory, P.O. Box 62, Oakridge, TN 37830.

Technical Support Document Number	Title	Administrative Record Number
1	The Standard Evaluation Technique	9561.00
2	Statistical Analysis	9562.00
3	Energy Budget Levels Selection	9563.00
4	Weighting Factors	9564.00
5	Standard Building Operating Conditions	9565 00
6	Draft Regulatory Analysis	9566 00
7	Draft Environmental Impact Statement	9567.00
8	Economic Analysis	9568.00
9	Passive & Active Solar Heating Analysis.	9569.00
10	Climate Classification Analysis	9570 00

Additional documents are the phase one/base data for the Development of Energy Performance Standards for New Buildings (Final Report, PB–286 898; Climatic Classification, PB–286 900; Data Collection, PB–286 902; Residential Data Collection and Analysis, PB–286 899; Data Analysis; PB–286 901; Building Classification, PB–286 904; and Sample Design, PB–286 903), January 12, 1978.

ANPRM—43 FR 54512, November 21, 1978.

NPRM—44 FR 68120, November 28, 1979.

Draft Final Environmental Impact Statement, Building Energy Performance Standards (DOE, April 1980).

Draft Regulatory Analysis.

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DOE-CS

Federal Price Support Loan Program for Energy from Municipal Waste Resource Recovery Facilities (10 CFR Part 485)

Legal Authority

Energy Security Act (ESA) Title II, Subtitle B, P.L. 96–294.

Reason for Including This Entry

The regulations to be developed by DOE will establish policy and set forth procedures whereby municipalities may submit applications for price support loans for energy produced and sold by municipal waste resource recovery facilities. These regulations are precedent-setting. The regulations will be issued in two phases.

Statement of Problem

In 1980, approximately 156 million tons of municipal solid waste and dry sewage sludge solids are potentially available for energy recovery. Should all these wastes be utilized for energy production, they could produce the equivalent of over 200 million barrels of oil annually.

In addition to municipal solid waste, about 14 million barrels of oil equivalent are potentially recoverable from the 30 million tons of process wastes generated by U.S. industry annually. Also, appreciable amounts of energy can be conserved through waste materials recycling processes. The magnitude of the potential energy production from all facets of wastes indicates that resource recovery systems could make a major contribution to national energy goals.

The proposed rulemaking will provide inducements to recover a substantial portion of the energy potential of solid and industrial process wastes. The initial phase of the regulations (phase 1) will establish the components for setting the amount of price support loans. The main regulations (phase 2) will cover the remaining components of the price support loan program, including procedures for filing applications, criteria for project eligibility and approval, deadlines for filing, etc.

A price support loan program for municipal waste to-energy systems could encourage projects to go forward that might otherwise be deferred because projected initial project costs resulted in disposal fees that were not competitive with the prevailing costs of landfill at the time the project was initiated. A price support loan affects the operational costs of a plant, having the effect of reducing the disposal fee. Without a price support loan in the early years, a project with a high initial disposal fee might not go forward despite its economic feasibility when calculated on a life cycle basis.

Alternatives Under Consideration

DOE is considering several options for the application of proposed price support loans. These include support based upon the quality of product, the quantity of product, the unit price received for product, and full or partial purchase of product by the Federal Government.

DOE is also considering other mechanisms for support of municipal solid waste energy recovery projects as specified in the Energy Security Act. These mechanisms include loan guarantees, construction loans, and price guarantees.

Summary of Benefits

Sectors Affected: Municipalities, counties, and special authorities (State and local); private industries in the role of energy buyers, waste disposers or project developers; investor-owned and municipally-owned utilities and their customers; investment banking companies and financial underwriters; waste processing equipment and systems manufacturers, and wholesale and retail traders; project engineering consultants; consumers of petroleum products; and the general public.

This regulation will significantly accelerate municipal waste reprocessing. Although these technologies may be economically marginal today, on a life-cycle basis they are attractive and will reduce our vulnerability to petroleum supply disruptions.

The proposed regulation will tend to reduce costs and prices of end products from municipal waste reprocessing facilities for individual levels of government, industries, and regions. In addition to contributing to the displacement of a significant amount of fossil fuels, primarily oil, this regulation also has the effect of creating both construction and permanent jobs. The facilities assisted under this price support program will also divert municipal wastes from landfills and reduce the volume for ultimate disposal by communities by 85 to 95 percent. Pollution of ground, water, and air will be significantly reduced.

Summary of Costs

Sectors Affected: The Federal Government.

The total Federal assistance available under this program is $160 million. Existing facilities may apply for a 5-year price support loan; new projects may

apply for a 7-year loan. No payment can be based on a unit value of support greater than $2.00 per thousand Btu's (MBtu) of energy produced and sold. Beginning in the second year, the amount of the loan declines in each succeeding year, to zero at the end of the 5- or 7-year loan term. For example, with a 7-year loan, the payment in year 2 would equal the per unit value multiplied by 6/7; in year 3 the proportion delines to 5/7; etc. Repayment begins in year 8.

Related Regulations and Actions

Internal: Urban Waste Demonstration Facilities Guarantee Program (10 CFR 495).

Municipal Waste Reprocessing Demonstration Program Facilities Evaluation and Assessment Guidelines (10 CFR 492).

Loan Guarantee for Alcohol Fuels Biomass Energy and Municipal Waste Energy Programs (10 CFR Part 799), Proposed August 19, 1980.

External: None.

Active Government Collaboration

Environmental Protection Agency; Department of Commerce.

Timetable

NPRM (Phase 2)—November 1980.
Public Comment Period (Phase 1)—November/December 1980.
Final Rule (Phase 1 and 2)—January/February 1981.

Available Documents

NPRM (Phase 1)—45 FR 63822, September 25, 1980.

Public comments (Phase 1 public comment period was September/October 1980) and comments from Phase 1 public hearing (October 14, 1980) are available from Agency Contact.

Environmental Assessment, July 19, 1979; this document can be obtained from Room 1F-059, 1000 Independence Avenue, S.W., Washington, DC 20585, (202) 252-9397.

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DOE-CS

Standby Federal Emergency Conservation Plan (10 CFR 477)

Legal Authority

The Emergency Energy Conservation Act of 1979, Title II, P.L. 96-102, 93 Stat. 757, to be codified at 42 U.S.C. § 8501.

Reason for Including This Entry

The Department of Energy (DOE) issues this rule to conform to the requirements of the Emergency Energy Conservation Act of 1979 (EECA). The Standby Federal Emergency Energy Conservation Plan (the Federal Plan) is one element in the framework provided by EECA for a coordinated national response to a severe energy supply interruption.

State of Problem

Serious disruptions due to continued high dependence on insecure crude oil imports have occurred recently in the gasoline and diesel fuel markets of the United States. Because it is likely that such disruptions could recur, and urgent need exists for Federal, State, and local governments to establish emergency energy conservation measures for gasoline, diesel fuel, home heating oil (middle distillates), and other energy sources which may be in scarce supply.

The EECA, passed by Congress on November 5, 1979, provides the framework for national, statewide, and local responses to serve energy supply disruptions. Under the terms of the Act, if the President finds that a "severe energy supply interruption" exists or is imminent, or that actions are necessary to restrain domestic energy demand under the terms of international energy agreements, he may establish emergency energy conservation targets for the Nation generally, and for each affected energy source (e.g., gasoline). Within 45 days from the publication of the targets, the Act requires States to submit to DOE emergency conservation plans containing measures designed to meet or exceed the energy savings targeted by the President. Section 213 of the Act requires that DOE establish a Standby Federal Emergency Energy Conservation Plan containing measures designed to reduce the consumption of targeted energy sources. If, after a period of not less than 90 days, a State is not substantially meeting its target, and a shortage of 8 percent or greater of the targeted energy source will persist for an additional 60 days, the President may impose upon the State all or a portion of the measures contained in the Federal Plan.

Because the transportation sector accounts for almost one-half of the Nation's petroleum consumption, and the greatest potential for fuel savings within this sector is related to the use of passenger automobiles, DOE gave primary emphasis in the Federal Plan to measures which are designed to reduce the demand for gasoline and other motor fuels. However, DOE included one non-motor fuel measure (mandatory building temperature restrictions) because it has already demonstrated the potential for savings of 200,000 to 400,000 barrels per day of oil equivalent.

Several of the measures referred to above are interim final rules, while others are proposed rules. Included in the interim final rules are:

1. Public information measures, intended to inform motorists about fuel conservation actions they can take, including efficient operation and maintenance of vehicles, alternative means of travel, and trip planning. Additionally, the rules require gasoline station owners to have available working air pumps and tire pressure gauges and informative, prominently displayed signs regarding the energy efficiency of proper tire pressure;
2. Minimum automobile fuel purchase restrictions, which set forth restrictions on any minimum gasoline purchase scheme implemented under Federal authority (i.e., the minimum amount of gasoline which may be purchased for a vehicle with 6 or more cylinders shall be $7.00, and for vehicles with fewer then 6 cylinders, the minimum amount shall be $5.00);
3. Odd-even motor fuel purchase restrictions, which set forth restrictions on any odd-even gasoline purchase program adopted by the Federal Government;
4. Portions of the employer-based commuter and travel measure, which requires private and public employers of a certain size to undertake measures to encourage the use of energy-efficient modes of transportation by their employees in commuting to work;
5. Speed limit enforcement measures, which require States to increase immediately the compliance level for the 55 mph speed limit, and take additional steps to reduce speed limits depending on the severity of the shortage.
6. Mandatory temperature restrictions, which prescribe thermostat levels for heating, cooling, and hot water in most nonresidential buildings.

Included as proposed rules are:

1. Portions of the employer-based commuter and travel measure, including employer subsidization of employees' cost for mass transit, and "work-at-home" arrangements;

2. The compressed workweek measure, requiring all but exempted Government and business activities to reduce their work week by one day; and

3. The vehicle use sticker measure, which prohibits the operation of certain motor vehicles on either one, two, or three preselected days of the week.

Most of the measures are much more intricate than can be captured in this brief analysis. DOE suggests the Federal Plan be read in order to gain a better appreciation of each measure. In addition to the demand reduction measures, the Federal Plan also contains a section which describes the contents, review, and approval of State emergency conservation plans.

Alternatives Under Consideration

The Act requires that DOE develop emergency conservation measures designed to reduce the public and private demand for certain fuels in the event of an energy supply emergency. The legislation also establishes criteria to judge the suitability of various measures for inclusion in the Plan.

Demand reduction measures may be implemented by Federal, State, or local government officials. Measures may be voluntary or mandatory, designed to achieve three goals: a reduction in energy use through a reduction in product or service output; improvements in efficiency which will reduce the energy required for the same output; and switching from a fuel in short supply to one that is more abundant.

DOE employed a systematic process in selecting demand restraint measures for inclusion in the Federal Plan. First, we analyzed the specific characteristics of U.S. energy demand in order to ascertain which sectors were likely to experience the most severe impact of an energy supply interruption. Next, we analyzed past shortages and devised demand restraint measures to meet a probable future shortage. We reviewed existing literature and surveyed the measures already in operation in various States to develop a catalogue of measures for inclusion in the Federal plan. Finally, we subjected these measures to an increasingly rigorous review to eliminate those which conflicted with statutory requirements. Other reasons for eliminating measures included their relatively minor energy savings, or their perceived unacceptable impacts on public health, the national economy, and the environment. However, some measures not selected for inclusion within the Federal Plan may well be appropriate for inclusion in State plans in States where they could result in significant energy savings and could be readily enforced. Examples of these measures are:

1. school schedule modification;
2. electricity end-user measures;
3. electric utility conservation measures;
4. commercial and industrial boiler efficiency improvements;
5. industrial and utility fuel switching;
6. reductions of lighting energy use; and
7. building insulation and weatherization measures.

Because the transportation sector accounts for nearly one-half of the Nation's average daily consumption of petroleum products, we targeted this sector for concentration in the Federal Plan. The greatest potential for fuel savings in transportation exists in the use of gasoline in passenger automobiles, which now account for more than 50 percent of all transportation energy consumption. For these reasons, all but one of the measures contained in the Federal Plan address the consumption of gasoline and motor fuels.

Summary of Benefits

Sectors Affected: All sectors of the economy, particularly transportation related industries; and the general public.

The benefits accruing from the Federal Plan are difficult to measure because it is a standby plan. We will implement it only after the States have been given an opportunity to develop and administer their own emergency conservation plans. The State plans may include elements of the Federal Plan. Publication of the interim final rule in February, 1980 has sparked an intense debate at all levels of government and the private sector as to the efficacy of various emergency conservation measures. It is clearly in the national interest that a standby plan be prepared so that our Nation will be able to respond within a coordinated framework to a severe energy supply interruption.

The average daily demand for gasoline in 1979 was just over 7 million barrels per day (BPD). Estimated energy savings (primarily gasoline) for the measures contained in the Federal Plan are:

Measure	Estimated reduction (in thousand BPD)
Public information	70-200
Minimum fuel purchase restrictions	Unknown
Odd-even purchase restrictions	Unknown
Employer based commuting	55
Speed limit (the range indicated depends on the degree of enforcement and designated speed limits).	30-400
Compressed workweek	300
Building temperature restrictions (measured in barrels/oil equivalent).	200-400
Vehicle-use sticker (the range indicated depends on the number of non-driving days from 1 to 3).	265-1,350

Summary of Costs

Sectors Affected: All sectors of the economy, particularly transportation related industries; and Federal and State government.

The actual costs associated with this plan depend on the extent of the energy shortfall, how long the shortfall lasts, and which of the standby measures are actually implemented. Implementation costs will be borne by all units of government as well as by the private sector. To give an indication of how much it might cost to implement portions of the standby plan in an energy shortfall, consider the following example. A minimal program to reduce gasoline consumption by 8 to 10 percent could include the public information, employer-based commuting, and 55 mph speed limit enforcement measures. We estimate that the costs to the Federal Government of implementing these three measures would total roughly $100 million.

Under the public information measure, gasoline station owners will be required to have available tire pressure gauges and operating tire pumps. According to the employer-based commuter and travel measure, employers over a certain size will be required to develop for each affected worksite a program to reduce work-related travel by employees. It should be emphasized that these substantial costs are incurred only in the event of an energy shortfall.

Administrative costs associated with developing State standby plans will total about $10 million.

Related Regulations and Actions

Internal: On July 16, 1979, the Emergency Building Temperature Restrictions became effective. The regulations, which prescribe heating and cooling limits for most nonresidential buildings, were extended until January 16, 1981 by Presidential Proclamation on April 15, 1980.

External: Many State Energy Offices have begun to design emergency conservation plans. We are encouraging States to submit plans to DOE prior to

the actual publication of mandatory emergency conservation targets.

Active Government Collaboration

An interagency task force has been created to ensure that effective input from all Federal agencies is heard in the development of the Federal Plan. Included on this task force are representatives from the Departments of Defense, Labor, Agriculture, Health and Human Services, Transportation, and Commerce; the General Services Administration; and the Postal Service.

Timetable

- Final Rule—DOE expects to publish the Final Rule in December 1980. The Final Rule may incorporate both the interim and the proposed rules.
- Regulatory Analysis—will accompany Final Rule.

Available Documents

Standby Federal Emergency Energy Conservation Plan—Interim Final and Proposed Rules (10 CFR 477), published February 7, 1980.

Standby Federal Emergency Energy Conservation Plan Docket CAS-RM-79-507. Transcripts of all public hearings and supporting documents are available for review in the Freedom of Information Office. Correspondence should be addressed to: Milton Jordan, Director, Freedom of Information Office, Department of Energy, 1000 Independence Avenue, S.W., Room 5B-138, Washington, DC 20585.

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DOE-Economic Regulatory Administration

Amendments to Puerto Rican Naphtha Entitlements Regulations

(10 CFR Parts 211* and 212*)

Legal Authority

Emergency Petroleum Allocation Act of 1973, as amended 15 U.S.C. § 751 *et seq.*

Reason for Including This Entry

The regulation could have a significant impact on the competitive position of the Puerto Rican petrochemical industry in relation to its main competitors, the petrochemical producers on the United States mainland. Additionally, any increased entitlement benefits to this segment of the industry would result in corresponding increased crude oil costs to the domestic refining industry.

Statement of Problem

During the 1950s and 60s the Federal Government and the Puerto Rican government encouraged the development of a refining and petrochemical industry in Puerto Rico. Commonwealth Oil Refining Company (CORCO), Phillips, Sun, and Union Carbide were among the major firms that invested large amounts of capital in refinery facilities, based on the tax relief afforded by the Puerto Rican government and the allocation of substantial quantities of low cost foreign crude oil and naphtha (a volatile, colorless, distillate product between gasoline and refined oil) by the Federal Government. Both naphtha and crude oil are "feed-stocks" convertible into one or more end products in the process of refinery operations and petrochemical production.

Two major considerations governed the joint policy of the Puerto Rican and the Federal governments towards the establishment of this refining capacity. First, the policy was based on the availability of low-cost imported feedstock, particularly naphtha, which provided a cost advantage over petrochemical producers on the mainland. This advantage was needed to offset the higher shipping and other costs of starting up the industry in the relatively underdeveloped economy of Puerto Rico. A second major consideration was that the new refinery facilities would expand employment and provide Puerto Rico with fuel for manufactur/, transportation, and agriculture.

Since the 1960s, the petrochemical industry in Puerto Rico has grown to such an extent that it now contributes greatly to U.S. petrochemical capacity and to the economy of Puerto Rico. In 1977, petroleum-related industry in Puerto Rico contributed more than $2 billion to the island's economy, approximately one-third of its total income. In addition, 10 percent of U.S. petrochemical output is now located in Puerto Rico.

Despite these gains, Puerto Rican oil refineries have been severely affected by the world-wide increase in the price of imported crude oil, coupled with the imposition of price controls on domestic crude oil by the Federal Government.

The combination of soaring prices for imported naphtha and crude oil, coupled with Federal regulatory policy which enabled mainland refiners to purchase cheaper domestic crude oil, has reversed the feedstock cost advantage that the Puerto Rican petrochemical industry formerly enjoyed. Mainland competitors now pay less for feedstocks than Puerto Rican refiners.

To lessen the competitive disadvantage to Puerto Rican companies of higher feedstock costs, the Federal Energy Administration (FEA) amended the entitlements program on July 20, 1976, to permit Puerto Rican petrochemical producers to receive entitlement benefits for imported naphtha feedstocks. (An "entitlement" is a credit given by DOE to a refiner, and is equivalent to the difference between the average (volume weighted) delivered cost per barrel of uncontrolled crude oil and the average (volume weighted) delivered cost per barrel of domestic price-controlled crude oil.) The maximum value of the per-barrel naphtha entitlement for any month cannot exceed the value of a single crude oil runs credit. Entitlement obligations are imposed on domestic price controlled crudes so as to raise their cost to that of comparable decontrolled crude oils. Each refiner receives a runs credit for every barrel of crude oil processed, which is the uniform distribution of entitlement monies collected. The entitlement credit, used in this manner, would reduce the price of purchased feedstocks. FEA determined that it would be inappropriate to grant the full crude oil entitlement benefit to naphtha imports in months when the differential between the prices of imported and domestic naphtha is less than that month's per-barrel crude oil runs credit. Accordingly, the rules the FEA adopted tie the entitlement credit for naphtha imported into Puerto Rico to the difference between the average (volume weighted) cost for imported naphtha and an imputed domestic naphtha price, divided by a modified crude oil runs credit (See § 211.67(d)(5)(iii)). This imputed value is set at 108 percent of the average (volume weighted) cost of crude oil to refiners. (It is necessary for the Government to impute this price because very little naphtha is sold domestically.)

These rules are now the responsibility of the Department of Energy (DOE), and are administered by the Economic Regulatory Administration (ERA) within DOE. DOE believes that two factors in the current regulations are causing problems: (1) the naphtha entitlement

value is limited to a crude oil entitlement runs credit, and (2) the factor used to impute the domestic naphtha price is too low. FEA never expected that it would need to grant more than a full crude oil runs credit, since world naphtha prices historically have paralleled crude oil prices. However, during the last year, the prices for imported naphtha have increased much faster than those for crude oil. Further, ERA's review of current data on naphtha prices and crude oil costs show that the factor presently used to impute the domestic naphtha cost is much too low. As a result of these factors, approximate feedstock costs equalization of Puerto Rican petrochemical producers with their U.S. mainland competitors has not been achieved under the existing regulations.

In recognition of the problems facing the petrochemical industry in Puerto Rico, DOE's Office of Hearings and Appeals (OHA) has provided exceptional relief to two of the three petrochemical companies in Puerto Rico that import naphtha. This interim relief was given in order to provide the Economic Regulatory Administration (ERA) with sufficient time to address these issues through the rulemaking process. One firm has been granted relief that allows it to earn two entitlement runs credits for each barrel of imported naphtha run in its petrochemical plant, and the second firm is eligible for increased entitlements for each barrel of imported naphtha processed in excess of a certain monthly level.

Alternatives Under Consideration

DOE will consider several options for better calculating the imputed cost of domestically produced naphtha. The cost of naphtha to the mainland domestic petrochemical industry is a central issue in determining the appropriate level of price protection that should be afforded through the entitlement program to maintain a competitive petrochemical industry in Puerto Rico. These Puerto Rican producers find it difficult to compete with mainland domestic firms because the mainland firms have access to naphtha produced from lower cost domestic crude oils.

The possible approaches to imputing a domestic naphtha price that we are examining include:

- Retaining the current program of imputing a price based on domestic crude oils.
- Adopting a means of imputing the value of domestic naphtha based on its value as a major component in the motor gasoline pool.
- Calculating an imputed price for domestic naphtha by subtracting a fixed cost adjustment from the wholesale price of unleaded regular gasoline. The fixed cost adjustment would be derived by comparing wholesale gasoline and imputed naphtha prices (calculated according to the formula in the above alternative) during a recent 12-month reference period.
- Retaining the current approach of imputing a price based on domestic crude oils, but periodically changing the factor to reflect changes in world market naphtha prices.

In addition to examining changes in the ways of calculating the imputed cost of domestically produced naphtha, DOE has proposed increasing the maximum naphtha entitlement benefit to two run credits, rather than the single runs credit ceiling which currently applies.

Summary of Benefits

Sectors Affected: Puerto Rican petrochemical industry and economy; and users of naphtha derived petrochemicals.

Any of the alternative proposals should increase the competitive position of the Puerto Rican petrochemical industry with petrochemical producers located on the mainland. The Puerto Rican petrochemical industry maintains that if no regulatory changes are made to equalize their naphtha feedstock costs with those of firms operating on the Gulf Coast, they will be forced either to seriously trim their operations or incur large operating losses. In fact, one major Puerto Rican petrochemical plant has already closed. As we formerly stated, the development of refining and petrochemical facilities has had a great impact upon the economy of Puerto Rico. Thus, the proposed changes, in making the Puerto Rican petrochemical industry more competitive, would have a direct positive effect on Puerto Rico's economy.

The proposal should reduce the costs of naphtha-derived petrochemicals to U.S. consumers by a small amount.

Summary of Costs

Sectors Affected: Domestic petroleum refining industry; and U.S. consumers of petroleum products.

None of the proposed changes to the Entitlement Program will increase ERA's compliance or administrative costs. There will be no added reporting requirements for the petroleum industry. However, by allowing naphtha feedstocks imported into Puerto Rico to earn increased entitlement benefits, credits available to domestic refiners of crude oil are reduced. This would increase the cost of crude feedstock to domestic refiners and, in turn, this could result in a small price increase in oil products to U.S. consumers.

An increased naphtha entitlement value might also have the adverse effect of increasing the price of naphtha in the world marketplace.

Related Regulations and Actions

None.

Active Government Collaboration

None.

Timetable

Final Rule—December 1980.
Final Rule Effective—30 days after it is issued.

Available Documents

NPRM—45 FR 59818, August 28, 1980.
Draft Regulatory Analysis, September 4, 1980.
Public comments (public comment period ended November 10, 1980).

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DOE-ERA

Crude Oil Resales Pricing Revisions (10 CFR Parts 211* and 212*)

Legal Authority

Emergency Petroleum Allocation Act of 1973, as amended, 15 U.S.C. § 751 *et seq.*

Reason for Including This Entry

Apparent violations of price regulations by companies buying and reselling crude oil have received considerable attention from the media and the Congress. At the same time, members of the crude oil reselling industry have complained of inequities and ambiguities in the regulations affecting them.

Statement of Problem

With the exception of the group of resellers who entered into business after December 1977 (Class C), who are allowed a uniform maximum markup of 20 cents per barrel in accordance with a rulemaking issued July 29, 1980, firms are limited to the profit or loss experienced in a base reference period. Companies in existence in May 1973 (Class A) may earn the net (except for income taxes) per-barrel markup they earned in the month of May 1973.

Companies beginning business after May 1973 and before December 1977 (Class B) may earn the net per-barrel markup they earned in November 1977. With each Class A and Class B company setting its own Permissible Average Markup on the basis of sales in a particular month, one company earning an average of a few cents a barrel might be in violation, while another earning perhaps 50 cents per barrel might be in compliance. Average markups for the industry in recent years have been in the order of 9 cents to 14 cents per barrel.

A price-control system which allows a profit on each transaction is likely to encourage superfluous transactions. Investigations show that numerous "paper transactions" have been inserted in crude oil supply chains in order to lower average markups into compliance with the regulations.

Alternatives Under Consideration

Various uniform Permissible Average Markups ranging from 1 cent to 25 cents per barrel were proposed in an NPRM (October 1979). Comments were requested on the alternatives.

A Permissible Average Markup of 20 cents per barrel was proposed. This alternative would be consistent with the currenty regulatory scheme and would not require extensive revisions to the regulatory structure in the short period remaining for price controls, which will expire September 30, 1981. Thus, it would be less burdensome on the industry and would not require changes in industry practices. It would also be consistent with the 20 cent markup currently in effect for Class C resellers and would provide equitable treatment for all resellers. The allowable markup for Class C resellers is presently above the median average markup of 12–13 cents per parrel for Class A resellers in May 1973, where 99 percent of crude oil was resold at average markups of less than 20 cents per barrel. Therefore, we conclude that a 20-cent-per-barrel markup for Class A and Class B resellers to match Class C markups would be fair and compare favorably with historical average markups.

As an alternative to establishing a maximum average permissible cents-per-barrel markup, we have also proposed a maximum markup for each transaction. In addition, we proposed a low markup or no markup at all for transactions in which the reseller neither transported nor received crude oil into his storage facilities.

We have also proposed an alternative base period for Class B resellers which had no sales in November 1977. If a reseller came into business between May 1973 and November 1977, it would calculate its allowable permissible markup on the basis of November 1977 sales. If such a reseller had no sales in that month, there is no basis on which it would know whether it is in compliance with the regulations and no effective way they could be enforced against him. DOE's Economic Regulatory Administration (ERA) has proposed the last month prior to November 1977 in which the reseller sold crude oil as a substitute base period. This rule will be retroactive and will apply until uniform markups are specified by ERA.

Summary of Benefits

Sectors Affected: Crude oil wholesalers; petroleum refiners; and consumers of petroleum products.

Under the present regulations, each reseller of crude oil—except post-November 1977 firms affected by the amendment adopted on July 29, 1980—has its own individual price limitation. The complexity and inequity of this type of price control probably contributes to violations and makes enforcement difficult. Changing to a uniform markup limitation for all resellers will bring the benefits of clarity, simplicity, equity, and increased competition to the reseller industry. If competition allows, some crude oil resellers would increase profits. For buyers of crude oil and for ultimate consumers of petroleum products, there will be benefits if violations are reduced.

Administrative and enforcement costs to the Department of Energy will be lowered under a uniform markup regulation.

Summary of Costs

Sectors Affected: Crude oil resellers.

While adoption of a standard average permissible markup for all firms would allow some crude oil resellers to increase profits, others would bear costs if DOE requires them to reduce markups. However, under a 20-cent-per-barrel average allowable markup, probably markup increases by resellers constrained by the current regulations would be approximately matched by reductions by resellers with markups above 20 cents per barrel. The reason is that in the current moderately competitive market, few resellers realize their legal maximum net markup month after month.

In a fully competitive market, crude reseller price regulations would have little impact.

Related Regulations and Actions

None.

Active Government Collaboration

None.

Timetable

Final Regulatory Analysis—Fourth Quarter 1980.
Final Rule—December 1980.

Available Documents

NPRM—44 FR 62848, October 31, 1979.
Transcript of public hearings held December 6, 12, and 13, 1979.
Public comments on above NPRM.
Draft Regulatory Analysis.
ERA Docket No. ERA–R–79–48.
All documents are available in the DOE Freedom of Information Reading Room, Forrestal Building, Room 5B–180, 1000 Independence Avenue, S.W., Washington, DC 20585.

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DOE–ERA

Domestic Crude Oil Entitlements (10 CFR 211.67*)

Legal Authority

Emergency Petroleum Allocation Act of 1973, as amended, 15 U.S.C. § 751 *et seq.*

Reason for Including This Entry

This proposal has a significant economic effect; it would distribute the benefits of access to price controlled crude oil more equitably by reducing the post-entitlement cost differences between price-controlled (except Alaska North Slope controlled crude oil) and equivalent uncontrolled domestic crudes in Production Allocation for Defense Districts (PADDs) I–IV and PADD V. This would reduce the competitive advantage of refiners with access to above average proportions of controlled crudes in PADDs I–IV. This proposal would reduce the approximate $170 million cost advantage to refiners from refining controlled crudes in PADDs I–IV and reduce the approximate $45 million cost disadvantage to refiners for refining controlled crudes in PADD V.

Statement of Problem

The net cost of crude oil to a refiner is its delivered cost plus any entitlement obligation, less the runs credit. Entitlement obligations are imposed on price controlled crudes so as to raise their cost to that of comparable exempt

crudes. The runs credit is a uniform distribution of the money collected under the obligation and is applied to every barrel of crude oil processed by refiners in the United States.

The entitlements program is designed to equitably distribute the benefits of access to price-controlled crude oil. This is fully accomplished when the net costs of comparable price controlled and exempt crudes are equal. When first adopted in 1974, the entitlement program approximately equalized these net costs. Changes in relative market values of crude, due to restrictions on sulfur content in refined products, the reduced consumption of fuel oils, and foreign crude pricing and supply, no longer permit the equalization of net costs under the system adopted in 1974.

The net costs of controlled crudes have differed from the net costs of equivalent exempt domestic crudes, which are the most comparable to the price-controlled crudes. For example, in January 1980 the net cost of controlled crude was $6 to $9 less than that of equivalent exempt crudes in PADDs I–IV, and $2 and $4 more than the exempt crudes in PADD V. These differences had changed to $3 to $6 and $5 to $7 respectively by June 1980. In PADDs I–IV (essentially all of the United States east of the West Coast), the price controlled crudes had a total net cost approximately $170 million less than the net cost of an equivalent volume of exempt domestic crudes in that region. In PADD V (essentially the West Coast), the controlled crudes had a total net cost of approximately $45 million more than a comparable volume of exempt crudes in that region. These net costs differences are a measure of the degree to which the entitlements program does not accomplish equitable distribution of the benefits of access to price controlled crude oil.

Alternatives Under Consideration

We are developing a proposal to establish separate entitlement obligations for controlled crudes refined in PADD V and for those refined in PADDs I–IV. These separate obligations would equalize average controlled crude oil costs with average exempt domestic crude oil costs in each region, and achieve equitable distribution of the benefits of access to price-controlled crude oil.

In addition to the regional program, we are developing a proposed adjustment to the entitlement obligations in PADDs I–IV which would compensate for the price differences in high and low sulfur content crudes.

We are also considering taking no action at this time. Crude oil prices have recently declined, and these net cost disparities may be essentially removed by market actions. The traditional crude oil market, in which prices reflected differences in quality and location, may be restored. In that case, the domestic price disparities other than in PADD V would be essentially eliminated without changes to the entitlements program. Decontrol of price-controlled crude oil is also eliminating the impact of the disparity.

Summary of Benefits

Sectors Affected: Crude oil refiners; and marketers and consumers of petroleum products.

Refiners with below proportions of controlled crudes in PADDs I–IV and refiners of California, Nevada, Arizona, and Southern Alaska crudes in PADD V would obtain lower costs. Some marketers of products refined by these refiners may obtain lower costs, but the entire cost difference may not be passed on to these marketers as some refiners may not reduce selling prices. Similarly, reductions in costs to marketers may not be passed on to consumers.

Summary of Costs

Sectors Affected: Crude oil refiners; and marketers and consumers of petroleum products.

As the entitlements program redistributes costs among refiners, those firms that do not receive benefits incur costs equal to the total benefits. Therefore, all refiners other than those in the benefiting group would incur added costs. If market conditions allow, some of these added costs may be reflected in increased costs to marketers who in turn may increase prices to consumers.

The proposals do not require significant changes in data collection, reporting, or computation and should not impose any significant added administrative or enforcement burden on DOE or refiners.

Related Regulations and Actions

Internal: None.
External: None.

Active Government Collaboration

None.

Timetable

Public Comment Period—60 days following publication of NPRM.
Final Rule—January, 1981.

Available Documents

Regulatory Analysis—With NPRM.
NPRM—

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DOE-ERA

Gasohol Marketing Regulations (10 CFR Parts 211* and 212*)

Legal Authority

Emergency Petroleum Allocation Act of 1973, as amended 15 U.S.C. § 751 *et seq.*

Reason for Including This Entry

The Department of Energy (DOE) believes that amendments to the motor gasoline allocation and price regulations may be necessary to clarify the rights and responsibilities of refiners and marketers that enter the gasohol market. The amendments also are significant because of the degree of public interest in the further development of gasohol.

Statement of Problem

Gasoline supplies can be stretched further if increased use is made of gasohol, which is a blend of ethanol (a kind of alcohol) and unleaded gasoline. Because the ethanol in gasohol can be produced from domestic resources such as grain, the President has set increased use of gasohol as a national goal. This would reduce our dependence on foreign oil.

Existing Federal regulations on the allocation of motor gasoline control the distribution of gasoline in the United States. Price regulations control the methods by which (1) refiners allocate costs to gasoline in total and to individual grades of gasoline, and (2) marketers set selling prices for petroleum products. Unless these rules are appropriate to the growth of the gasohol market, it will be difficult for new and existing businesses to plan production and distribution of gasohol. Therefore, DOE is considering amendments to the regulations which will clarify the criteria under which DOE will assign supplies of unleaded gasoline to blenders for gasohol production, clarify the responsibilities of gasohol producers in marketing gasohol pursuant to the regulations, and amend the methods by which refiners must allocate ethanol costs and marketers set prices for gasohol.

The current regulations do not specify criteria to be employed or procedures to

be followed to assign unleaded gasoline to potential blenders. The only recourse under the current regulations is to apply for an exception through DOE's Office of Hearings and Appeals (OHA). As the gasohol market grows, this approach may be an inappropriate device to deal with increasing numbers of applications by prospective gasohol blenders. Furthermore, unless the allocation regulations were amended, gasohol marketers would have to assume that gasohol would have to be allocated by applying the regulations to the unleaded gasoline which constitutes 90 percent of the gasohol blend. This, however, may be entirely inappropriate to the development of a strong and viable market for this product. Finally, application of the current refiner price rules to gasohol requires that the refiners allocate ethanol costs among all barrels of a grade of gasoline (e.g., unleaded regular gasoline). To the extent that the costs associated with blending and marketing gasohol must be attributed to other grades of gasoline and cannot be recovered in the price of gasohol alone, a disincentive exists for refiners to enter the gasohol market. Correction of these problems would supplement the strong position previously taken by DOE in support of the development of gasohol.

Alternatives Under Consideration

(A) DOE could do nothing at this time, in which case the Office of Hearings and Appeals would still provide an avenue of relief for firms entering the gasohol market. But there are major disadvantages in inaction, including continued uncertainty over rules applicable to gasohol, possible unleaded gasoline supply dislocation, and a possibly unmanageable caseload for OHA.

(B) Deregulation of gasohol must be considered as an alternative, since price and allocation controls on motor gasoline will expire on September 30, 1981. This would allow gasohol blenders and marketers to compete in the market for the unleaded gasoline blend stocks they need to mix with ethanol and would not require a large bureaucracy to implement. However, deregulation of unleaded gasoline for gasohol blending suggests enforcement problems with other unleaded gasoline continuing under controls.

(C) DOE could amend the allocation and price regulations to provide for an appropriate passthrough of ethanol costs to gasohol, specify the criteria by which DOE will assign supplies of unleaded gasoline to a potential gasohol marketer, and create new provisions for the allocation of gasohol within a refiner's system.

Summary of Benefits

Sectors Affected: Gasohol refiners, ethanol producers, gasohol marketers, retailers, and users; and the general public.

Allocation of unleaded gasoline for blending with ethanol to produce gasohol could provide a regulatory framework within which ethanol fuel production could increase, perhaps from the present 60 million gallons per year to as much as 300 million gallons per year by 1982. Gasohol use may eventually reach 3 billion gallons per year, or 3 percent of present gasoline consumption, as a result of this and other measures. In addition, use of gasohol would also reduce dependence on foreign oil (see the Report of the Alcohol Fuels Policy Review, DOE, June 1979).

Summary of Costs

Sectors Affected: Refiners which manufacture unleaded gasoline; resellers and retailers marketing those refiners' unleaded gasoline production; ethanol producers; and gasohol consumers in some areas.

Allocation of unleaded gasoline to gasohol blenders reduces the amount of unleaded gasoline available to other distributors. Because we expect ethanol production and blending to occur primarily in the Midwest, near resources to produce ethanol, this rule could result in a shift of gasoline supplies to the Midwest at the expense of other regions. DOE has not yet determined whether the gasohol, once blended, would flow back to the regions affected by reduced gasoline supplies. However, since the proposed amendments are expected to serve largely as a codification of certain procedures, or modification of those procedures, which are now undertaken by the Office of Hearings and Appeals to avert these costs, we are unable to state definitely that direct costs will occur or, if so, in what magnitude.

Related Regulations and Actions

Internal: DOE has already provided certain price incentives for the marketing of gasohol. DOE price regulations permit gasohol resellers and retailers to pass through as product costs the cost of nonpetroleum-based alcohol blended with gasoline (45 FR 20104, June 13, 1980). DOE has also issued a rule to permit refiners to allocate all of the costs of alcohol among the various grades of gasoline (44 FR 69594, December 5, 1979). DOE has issued a rule offering an entitlement benefit (a payment related to the difference in costs between imported and domestic crude) to alcohol producers of ethyl alcohol derived from biomass that is blended with gasoline for use as fuel (44 FR 63515, November 5, 1979). An Environmental Assessment (EA) has been prepared and published for public comment (45 FR 44961, July 2, 1980). On the basis of the Environmental Assessment, DOE has made a finding of no significant impact and determined that it is unnecessary to prepare an Environmental Impact Statement in conjunction with this rulemaking.

External: Gasohol marketing is encouraged by the National Energy Act motor fuel excise tax exemption on gasoline/alcohol blends, which is worth 4 cents per gallon of gasohol (at a 9 to 1 ratio) and 40 cents per gallon of ethanol if blended with gasoline. This is equivalent to $16.80 per barrel of ethanol. This exemption will continue through the year 1992 under the terms of the Crude Oil Windfall Profits Tax Act (P.L. 96-223, April 2, 1980, § 232(a)). Provisions of various State governments permit whole and partial exemptions from State motor fuel taxes for gasohol, in an attempt to ensure that gasohol is competitively priced.

Active Government Collaboration

DOE is cooperating actively with the Alcohol Fuels Commission on this issue.

Timetable

Final Rule—Fourth quarter, 1980.
Final Rule Effective—30 days after final rule issuance.

Available Documents

Regulatory Analysis (DOE/RG-0032).
Environmental Assessment (DOE/EA-0107).
NPRM—45 FR 34846, May 22, 1980.
Draft Analysis issued May 1980 (DOE/RG-0032).
Environmental Assessment—(DOE/EA-0107), 45 FR 44961, July 2, 1980.
Transcript of Public Hearing—Washington, DC, July 8 and 9, 1980; Des Moines, Iowa, June 23, 1980.

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DOE-ERA

Maximum Lawful Price for Unleaded Gasoline (10 CFR 212.83*)

Legal Authority

Emergency Petroleum Allocation Act of 1973, as amended, 15 U.S.C. § 175 *et seq.*

Reason for Including This Entry

These proposed regulations could have an annual economic effect of over $180 million.

Statement of Problem

The present regulations may contribute to unleaded gasoline price differentials between refiners which may lessen the competitiveness of independent marketers. Also, the current rules may encourage refiners to market a premium unleaded gasoline with an unnecessarily high octane although the production of an unnecessarily high octane gasoline is economically inefficient. Also, lack of a satisfactory higher unleaded octane gasoline could lead to fuel switching and contribute to unnecessary pollution of the environment.

Generally, under the current price regulations, the maximum lawful price refiners may charge for unleaded gasoline is the May 15, 1973, selling price of unleaded gasoline plus increased product and nonproduct costs. If a refiner did not sell unleaded gasoline on May 15, 1973, or 30 days prior thereto, as was the case for most refiners, the maximum lawful selling price is imputed. This imputed selling price is the weighted average selling price charged for leaded gasoline on May 15, 1973, of the same or nearest octane as the unleaded gasoline, plus one cent.

Experience has shown that some automobiles do not function satisfactorily on the minimum required grade of unleaded gasoline, 87 octane (R+M)/2

(Research Octane Number + Motor Octane Number)/2.

Research shows that a 90 octane (R+M)/2 unleaded gasoline would meet the requirements of almost all of these automobiles. However, a refiner newly marketing this grade would have a base price which still would be imputed from the May 15, 1973 selling price of the nearest octane leaded regular grade of gasoline. The current regulations encourage a refiner to increase the unleaded gasoline octane to bring it nearer to the premium leaded grade, generally 94 octane (R+M)/2, sold on May 15, 1973. By consuming more crude oil than is necessary, this increase, which will vary among refiners based on their refining capabilities, is wasteful and unnecessarily expensive to refiners and thus to motorists.

For most refiners, the comparable leaded grade to 90 octane (R+M)/2 was their "regular" leaded grade of gasoline, usually 89 octane (R+M)/2. However, some refiners were marketing a subregular grade whose octane was closer to the minimum unleaded grade and, in at least one instance, a refiner was marketing only a premium leaded gasoline. Those refiners with actual May 15, 1973 sales of unleaded gasoline generally had actual base prices which were higher than those imputed by other refiners, making their prices for unleaded higher.

This proposal would tend to remove inequities imposed by the prior regulations by decreasing base price differentials for unleaded gasoline among refiners and thus improve the competitive positions of independent marketers by removing price disparities in their purchase price.

Alternatives Under Consideration

The proposal provides for two alternatives for refiners to calculate a price for unleaded grades of gasoline. One proposal would recognize the higher cost of improving unleaded octanes by permitting refiners to allocate increased costs to different grades of unleaded gasoline at their discretion. Under current regulations, refiners may not automatically treat new grades of unleaded gasoline as separate product categories. DOE believes that the proposal will remove the disincentive for the introduction of new grades and will encourage the production of unleaded gasoline with more efficient octane ratings. Firms that introduce new grades of unleaded gasoline will automatically be permitted the pricing flexibility to apportion increased costs as the refiners deem appropriate to meet market conditions. This approach would not provide any additional potential revenues because it involves the reallocation of product and non-product costs. It would not provide any additional incentive to refiners to market a higher grade of unleaded gasoline.

The second alternative offers several options for refiners to use in establishing a higher base price for octane increases over the minimum required grade of unleaded gasoline. We based these options on the assumption that a higher base price, which includes a profit element, is necessary to encourage production of a premium unleaded gasoline. The rationale for stimulating this production is that motorists requiring this grade will otherwise purchase a higher octane grade of leaded gasoline and increase air pollution. Any of the base price increase options, however, are less costly by .5 to 1 cent a gallon to the public than the present regulation would be if the refiner needlessly raised the unleaded octane to benefit from higher premium leaded gasoline base prices under the present regulation. These options remove the disincentive for the production of unleaded gasoline with octane ratings close to the regular leaded gasoline sold on May 15, 1973 because current regulations require that the imputed selling price for such unleaded be calculated on the basis of the lower priced, lower octane leaded gasoline.

Summary of Benefits

Sectors Affected: Refiners, resellers, retailers, and consumers of unleaded gasoline; and the general public.

The effect of the proposed changes would be to decrease base price differentials for unleaded gasoline among refiners. This should translate into prices to independent marketers and resellers which are more comparable to prices being charged by other marketers and contribute to the improvement of their competitive positions. In addition, motorists should have a second grade of unleaded gasoline available at a lesser price than would otherwise be the case if they purchased an octane that is unnecessarily high. The availability of the second, higher octane grade may help prevent misfueling (the switching of a regular grade for an unleaded one) and the resultant pollution of the air. Misfueling occurs because motorists desire a higher octane gasoline to improve engine performance. The Environmental Protection Agency (EPA) contends that misfueling significantly contributes to air pollution.

Summary of Costs

Sectors Affected: Refiners, resellers, and retailers of unleaded gasoline.

The proposed changes could result in no increased costs to the consumer. Additional information is required to confirm this and will be incorporated, if a final rule is adopted, in a final Regulatory Analysis. We currently believe that the proposed revisions will be less costly to the public than the present regulations and that they will restrain potential waste of petroleum products.

Related Regulations and Actions

None.

Active Government Collaboration

None.

Timetable

Final Rule—December 1980.
Final Regulatory Analysis—Fourth Quarter, 1980.

Available Documents

NPRM—45 FR 54094, August 15, 1980.
Public comments on above NPRM, and comments from public hearing (September 11, 1980).
All documents are available in the DOE Freedom of Information Reading Room, Forrestal Building, Room 5B-180, 1000 Independence Avenue, S.W., Washington, DC 20585.
Draft Regulatory Analysis—August 1980.

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DOE-ERA

Motor Gasoline Allocation Regulations Revisions (10 CFR Part 211*)

Legal Authority

Emergency Petroleum Allocation Act of 1973, as amended, 15 U.S.C. § 751 *et seq.*

Reason for Including This Entry

The Department of Energy (DOE) motor gasoline allocation program has a significant influence on the energy sector of the Nation's economy. Changes to the overall regulatory scheme can have potential impacts upon every level of supply down to retail outlets and their customers. In addition, if the changes we propose succeed in reducing gasoline lines at retail stations during any future supply shortages, motorists will benefit as they will lose less time from work and waste less fuel waiting in lines.

Statement of Problem

DOE's Mandatory Petroleum Allocation Regulations apply to all domestic transactions in motor gasoline. The regulations operate to allocate the product to historical purchasers as measured during the base period of November 1977 through October 1978. Where supplies are inadequate to meet base period obligations, suppliers are required to recognize certain priority uses and to apply prorated reductions equitably among their customers.

Motor gasoline markets are constantly changing to reflect new marketing techniques, evolving consumer preferences, improvements in efficiency, and competitive advantages among firms. In this context, a rigid allocation system based on historical relationships cannot respond smoothly to recent shifts in demand, and this can result in inadequate allocations of gasoline to areas of greatest need. The principal means to reflect such shifts and changes in marketing practices are contained in procedures available under the program for allocating gasoline to new retail outlets and increasing allocations to existing firms. Additional flexibility is available through the program's State set-aside provisions, under which State Governors are authorized to allocate up to 5 percent of gasoline delivered to the State to meet emergency supply conditions. The allocation program also permits large or "prime" suppliers to a State to redirect a portion of supplies to areas in need as they see fit. However, the evidence to date suggests that these provisions have not been used to equalize regional impacts resulting from localized shortfalls.

A further contributing factor relating to regional supply disparities that have been experienced has been the relative differences in suppliers' allocation fractions. The allocation fraction is the primary measure of a supplier's ability to meet the needs of its historical customers. Each month, a supplier is required to offer to its historical purchasers a volume of gasoline equal to the volume purchased during the same month of the November 1977 through October 1978 base period. When a supplier's total available supply is less than its total obligations, the firm must reduce on a pro rata basis the amount supplied to its non-priority purchasers by the application of an allocation fraction. The numerator of the allocation fraction represents a supplier's allocation supply less obligations to priority use customers and State set-aside volumes. The denominator represents the supplier's base period obligations. If the allocation fraction is less than 1.0, all purchasers whose allocation level is subject to the fraction are offered only that portion of their base period volumes.

During the 1979 summer driving season, 18 States and the District of Columbia experienced moderately severe or severe gasoline lines at the retail level, according to DOE's Energy Liaison Center. The available evidence suggests that gasoline lines end apparent shortages at the retail level occurred mainly in densely populated urban and suburban areas. These areas appear most prone to gasoline lines because travel and gasoline demand paterns appear to have actually shifted during the generalized shortfall that occurred in 1979. This shift apparently was the result of reduced inter-city travel and travel to vacation and other rural areas by motorists who became concerned about the availability of gasoline. There was relatively less of a reduction of driving within urban regions where a lower percentage of the driving is discretionary.

Our tentative view is that if the present allocation system remains unchanged, the same parts of the Nation which suffered most of the gas lines in 1979—mainly urban areas—may again experience lines during a future supply shortage. To date, the allocation system has not provided sufficient flexibility to respond to these apparent demand shifts, and motorists in urban areas have had to bear a disproportionate share of the hardships associated with gasoline shortages.

On June 6, 1980, an NPRM was issued presenting for public comment alternative proposed revisions to the motor gasoline allocation program (45 FR 40078, June 12, 1980). The pending rulemaking proceeding is intended to identify and explore the extent of such inequities and to provide a public forum to consider the merit of proposed alternative revisions. This rulemaking proceeding is based upon a belief that it is prudent to identify and explore various options for improving the ability of our regulations to minimize the adverse effects of future shortages experienced at the retail level.

In addition, we have also become aware of certain unintended effects of our regulations. We are concerned that certain independently operated retail stations may be experiencing competitive difficulties as a result of their relative inability to obtain increased allocations for increased demand as easily under our regulations as many wholesaler- and refiner-operated stations. The pending proceeding is also intended to identify and explore the extent of such inequities and to provide a public forum to consider the merit of proposed alternative revisions.

Alternatives Under Consideration

Each of the alternative proposals that has been offered is being explored thoroughly and extensive opportunity for public comment and discussion will be provided. On the basis of full consideration of each, DOE may determine to adopt some or all of the following proposals, or may determine

that no action is warranted and terminate the proceeding.

Among the possible alternative regulatory changes that have been proposed are:

(A) More restrictive standards for making allocation assignments for new retail service stations and methods of limiting present interim supply procedures.

(B) More equitable standards for making allocation adjustments to existing service stations.

(C) Increased flexibility for refiners and retail marketers to shift volumes within their own distribution system in response to changing demand.

(D) Clarification of existing regulations to authorize State set-aside officials in emergencies to require a supplier of one brand of gasoline to deliver gasoline to other firms selling a different brand in order to meet emergency supply conditions.

(E) Authorization of resellers supplying more than one brand to maintain and base deliveries on separate allocation fractions.

(F) Substitution of an improved mechanism for providing allocations to geographic areas that have experienced unusual growth.

(G) Increased authority for State Governors to require intrastate redirection of gasoline in order to meet emergency supply conditions.

(H) Designation of vehicle leasing firms as consumers rather than resellers of gasoline (for purposes of the allocation regulations only).

Summary of Benefits

Sectors Affected: Refiners producing gasoline; wholesale and retail gasoline suppliers; wholesale and retail gasoline purchasers; and State governments.

The objective of the pending proposals to revise the allocation regulations is to reduce the distortions that may be occurring as a result of the program's inability to respond to long-term and temporary demand shifts. All of the identified sectors affected can benefit from improvements in the regulatory scheme that permit competition to direct supply toward demand. The qualitative benefits of adopting several of the proposed alternative revisions described above (A–H) are summarized briefly as follows:

(A) and (B)—The proposals to restrict new station access to increased allocations of gasoline and to expand existing station access to increased allocations would tend to alleviate apparent inequities being felt by certain independent gasoline station dealers under the current provisions. These changes would grant access to increased supplies to these groups on an equal basis and would tend to lend to increased economic efficiencies. The changes would remove a disincentive that may currently exist against upgrading and improving existing retail stations. This would lead to lower cost operations at the retail level and ultimately to lower prices paid by consumers. Adoption of these proposals would also introduce increased competition among firms operating at the retail level and remove any artificial advantages that the current program makes available to firms in a position to enter a market by constructing new stations.

(C)—The proposal to permit refiners and other retail marketers increased flexibility to shift allocations within their own distribution systems would enhance these firms' ability to respond to demand changes since the base period. Added flexibility to respond to real changes in the marketplace could contribute to more efficient distribution systems and decreased costs.

(D) and (G)—The proposals to authorize State officials in implementing the State set-aside program to require suppliers to make the product available to firms operating under a different brand and to order refiners to redirect gasoline supplies could improve the capability of the set-aside program to respond to emergency supply conditions. Currently, many States have adopted branding laws that prohibit such "cross branding" and the proposal would apply only to States that have no such restrictions. The increased flexibility provided to States under the proposals could be useful in resolving unusual or extreme supply problems.

(E)—The proposal to authorize wholesalers that supply more than one brand of gasoline to maintain separate allocation fractions would provide added flexibility to such firms under the program. Currently, firms supplied by more than one brand must apply a uniform allocation fraction to all purchasers irrespective of brand. Under the proposal, such firms would be permitted to place their customers on separate allocation fractions according to brand of gasoline. If adopted, this proposal would tend to relate a firm's supply condition as measured by the allocation fraction to the actual supply position of the ultimate refiner whose brand is associated with its gasoline products. This would operate to make the allocation program more in line with actual supply conditions among firms and could thereby tend to reduce the artifical effects of the regulatory program.

(F)—The proposal to modify the currently available adjustment to reflect unusual growth could, if adopted, correct a seasonal bias that may be present. Whether the correction would be worth the administrative costs associated with this change, however, is not clear.

(H)—The proposal to reclassify vehicle leasing firms as consumers rather than as resellers under the allocation program would tend to conform with the actual business fractions of such firms and enable them to obtain adequate supplies of unleaded gasoline for their essentially new car fleets.

Summary of Costs

Sectors Affected: Refiners producing gasoline; wholesale and retail gasoline suppliers; wholesale and retail gasoline purchasers; and State and Federal government.

(A) and (B)—The proposals to restrict new station access to increased allocations and to expand existing station access to increased allocations could disrupt supplier/purchaser relationships and entail added administrative costs among the identified sectors affected and the Federal Government. It is estimated that granting to existing service stations the opportunity to apply for increased allocations could contribute significantly to administrative costs of DOE Regional Offices processing such applications. It is estimated that a 25 percent increase in regional staff may be required to respond to existing station applications.

(C)—The proposal to permit refiners and other retail marketers increased flexibility to reassign allocations within their own distribution systems could result in increased administrative costs to such firms in accounting for changed allocations. Some suppliers may be in a position to use the flexibility to exert competitive pressure on other firms within a market. To some extent, this is a benefit that, if abused, could lead to increased concentration.

(D) and (G)—The proposals to authorize State officials to assign suppliers to make the product available to firms operating under a different brand and order refiners to redirect the product to respond to emergencies within their States would also add needed flexibility during a shortage. If exercised, the cross branding authority could be inconsistent with the brand identity objectives of larger firms. Motor gasoline, however, tends to be a readily exchangeable product and making this

authority available to States in an emergency could be a benefit to respond to a gasoline shortfall within a State.

(E)—The proposal to authorize wholesale purchaser-resellers that supply more than one brand of gasoline to maintain separate allocation fractions could grant supplier flexibility that could be used to the detriment of those of his purchasers who do not sell a major branded product. Possible effects of discrimination among such firms' non-branded purchasers are being examined and compensating limitations are under consideration.

(F)—The proposal to modify the current unusual growth adjustment could entail significantly increased administrative costs to suppliers and purchasers of gasoline and to the DOE. The large number of base period relationships that could be affected by the new provisions could result in significant disruptions that may not be worth the mitigating effects of the proposal modification.

(H)—The proposal to classify vehicle leasing firms as consumers of gasoline under the allocation regulations could potentially affect a large number of base period relationships. The modification, if adopted, would have little or no impact on the supply rights of these firms except for unleaded gasoline entitlements during a severe shortage. Otherwise, the modification should result in minimal increased administrative costs.

Related Regulations and Actions

Internal: An NPRM entitled "Motor Gasoline Allocations; Adjustments and Downward Certification" (44 FR 69962) was issued on December 5, 1979. On April 26, 1980, DOE issued a notice of intent not to adopt as a final rule its principal proposal on downward certification. A draft Regulatory Analysis was published at 45 FR 58788 (September 4, 1980). The alternative proposals remain under consideration.

External: None known.

Active Government Collaboration

DOE is actively cooperating with the Small Business Administration in the portions of this proposal concerning assignments for new retail outlets and adjustments for existing retail outlets.

Timetable

Final Rule—December 1980.
Final Rula Effective—30 days after issuance.

Available Documents

Draft Regulatory Analysis (DOE/RG-037).
NPRM—45 FR 40078, June 12, 1980.
Public comments (hearings held July 17, 21, 24, 28, 29 in Atlanta, Kansas City, San Francisco, Washington, D.C.).

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DOE-ERA

Motor Gasoline—Downward Certification (10 CFR 211.107*)

Legal Authority

Emergency Petroleum Allocation Act of 1973. 15 U.S.C. § 751 *et seq.*

Reason for Including This Entry

This proposed rulemaking is of great public interest; it will examine possible revisions to the Mandatory Petroleum Allocation Regulations that could improve the capacity of the gasoline marketplace to distribute available supplies in an equitable manner during a shortage. The pending proposals present alternative provisions that would require certain wholesalers of gasoline to report or certify to their suppliers reductions in their supply obligations attributable to closed service stations or other customers they previously supplied.

Statement of Problem

Under the allocation program, DOE determines a wholesaler's allocation entitlements by referring to the firm's purchases during a historical base period, which is currently November 1977 through October 1978. When a wholesaler's base period allocation obligations are increased by an Economic Regulatory Administration (ERA) assignment or adjustment, the firm may adjust upward its allocation entitlements by certifying to its suppliers the corresponding increase. However, when a wholesaler's obligations decrease because a relationship with a base period purchaser is terminated (e.g., a retail outlet it supplies goes out of business), there is no equivalent mandatory procedure to certify to its suppliers the corresponding decrease, except where previous upward adjustments have been granted to the firm.

The downward certification proposals are designed to assure that a wholesaler's entitlements from suppliers match more closely the firm's actual obligations to its purchasers under the program. The changes proposed are intended to restore this balance and to resolve the distortions the absence of a downward adjustment is having on the program's effectiveness as a measure of actual supply conditions.

Alternatives Under Consideration

On November 30, 1979, an NPRM (44 FR 69962, December 6, 1979) was issued presenting several alternative downward certification proposals. After reviewing the extensive public comments received on the alternative proposals, ERA announced on April 21, 1980 that it would not adopt the principal proposed provision and that the rulemaking proceeding would be continued to consider the merit of adopting the alternative proposals (45 FR 28148, April 28, 1980). The alternative proposals remain under consideration, and on August 28, 1980, ERA issued a draft Regulatory Anaylsis of the alternative proposals (45 FR 58788, September 4, 1980). The alternative proposals under consideration are as follows:

The first would require downward adjustment only as a condition precedent to receiving an allocation increase. Under this alternative, certain wholesalers referred to as "wholesale purchaser-resellers" under the regulations would not be required to decrease their allocations when their supply obligations decrease except to the extent that they wish to certify allocation increases to their suppliers.

The second would require adjustments to reflect an allocation decrease when retail outlets close but would not require an adjustment to reflect an allocation decrease when a reseller is relieved of its obligation to supply certain wholesale or bulk purchaser customers.

The third would require a wholesaler to report a decreased obligation only when a supplier's base period obligations are assumed by another supplier in accordance with the regulations. To a varying extent, ERA requires applicants to account for the reduced obligation when its Regional Offices approve applications for such reassignments.

The fourth would require a wholesaler to report a decreased allocation obligation only for decreased obligations due to station closings that occurred subsequent to the end of the current base period.

The fifth would apply prospectively from the date of the adoption of a final rule. Under this alternative, wholesalers would be required to report to their suppliers decreased allocations for lost business occurring in the future.

In connection with these alternatives, ERA stated that none are mutually exclusive, and that features from more than one alternative could be included in a final rule.

Summary of Benefits

Sectors Affected: Wholesale and retail gasoline suppliers; and wholesale and retail gasoline purchasers.

If adopted, a procedure that would require wholesalers to notify their suppliers of reduced needs by certifying a downward adjustment in the allocations of gasoline would tend to restrict the present ability that some wholesalers have under the rule to increase their share of a market solely by a complex manipulation of the allocation regulations. One objective of the allocation program is to minimize interference with market mechanisms and this may be frustrated in cases where wholesaler expansion is permitted beyond that which would occur in a free market. In the context of a generally fixed amount of available supply, the increases that some wholesalers are able to obtain under the present rules may often be made at the expense of existing retail outlets that have no comparable means of obtaining allocation increases. No action in this proceeding would continue the favorable treatment wholesalers receive, and this could, over the long term, contribute to economic inefficiency. The adverse impacts on the independent retail segment of the market would also continue.

A downward certification procedure would reduce wholesalers' flexibility to shift allocation volumes within markets and divert the product unlawfully to purchasers having no allocation entitlements under the regulations.

These restrictions would operate to contain motor gasoline within the allocation program and thereby assure that the product is available to firms having supply rights under the program. Adoption of a downward certification requirement could increase the allocable volumes of motor gasoline to certain independently operated retail service stations.

The various proposed downward certification provisions that are under consideration are being reviewed in conjunction with the pending revisions to the motor gasoline allocation programs as set forth in the Calendar entry herein entitled "Motor Gasoline Allocation Revisions (10 CFR Parts 205 and 211.)"

Summary of Costs

Sectors Affected: Refiners producing gasoline; wholesale and retail gasoline suppliers; and wholesale and retail gasoline purchasers.

Administrative costs to affected wholesalers, suppliers of wholesalers, and the ERA would be increased if a procedure were adopted to require wholesalers to report and certify to suppliers decreases in supply obligations attributable to closed service stations and other lost accounts. Wholesalers subject to such reductions would lose their flexibility under the present program to shift product to areas experiencing stronger demand, and this could lead to distortions and inefficiencies in the marketplace. Adoption of such a procedure would also restrict certain wholesaler increases in market share that have been occurring as a direct result of the absence of a downward certification procedure. Some costs could be associated with this result because an expanding independent marketing segment can operate to assure that competition achieves its goal of improving distribution of supplies and restraining price.

Related Regulations and Actions

Internal: An NPRM entitled "Motor Gasoline Allocation Regulations Revisions" was issued on June 6, 1980 (45 FR 40078). These proposals remain under consideration and any action taken thereon may take into account possible aspects of the downward certification proceeding.

External: None.

Active Government Collaboration

None.

Timetable

Final Rule—To be determined.
Final Rule Effective—30 days after issuance.

Available Documents

Draft Regulatory Analysis (45 FR 58788, September 4, 1980).

NPRM—44 FR 69962, December 6, 1979.

ERA decision to continue rulemaking proceeding to consider merit of adopting alternative proposals (45 FR 28148, April 28, 1980).

Public comments on NPRM and comments on public hearings (January 31 and February 1, 1980).

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DOE–ERA

Natural Gas Curtailment Priorities for Interstate Pipelines (10 CFR Part 580*)

Legal Authority

Natural Gas Act, 15 U.S.C. § 717 *et seq;* Natural Gas Policy Act of 1978, §§ 401, 402, 403, 15 U.S.C. §§ 3391–3393; Department of Energy Organization Act, §§ 301(b), 402(a)(1)(E), and 501, 42 U.S.C. §§ 7151(b), 7172(a)(1)(e), and 7191; E.O. 11790 (39 FR 23185), E.O. 12009 (42 FR 46267).

Reason for Including This Entry

The Department of Energy Organization Act (DOE Act) makes the Secretary of Energy responsible for reviewing and establishing natural gas curtailment (rationing) priorities. This rule will implement the curtailment priorities established by the Natural Gas Policy Act (NGPA) and will address, as indicated by our review, any other changes we determine to be necessary. We are including this rule because of its potentially far-reaching effects on interstate pipelines and local distributors and their natural gas customers.

Statement of Problem

Natural gas curtailment priorities deal with the manner in which natural gas will be allocated to customers of interstate pipelines when there are supply or capacity shortages. Under the DOE Act, the Secretary of Energy is responsible for establishing and reviewing priorities for curtailments. The Secretary of Energy has delegated this authority to the Administrator of the Economic Regulatory Administration (ERA). Under the DOE Act, the Federal Energy Regulatory Commission (FERC) administers and implements the curtailment policies developed by the ERA.

Historically, FERC's predecessor, the Federal Power Commission (FPC), had exclusive Federal jurisdiction under the authority of the Natural Gas Act (NGA) for curtailment of natural gas in interstate pipelines. The FPC dealt with curtailment of natural gas on a case-by-case basis. From the rulings issued in these cases by the FPC, a priority system developed which ranked end-users of natural gas from high (last to be curtailed) to low (first to be curtailed). The FPC priority system generally placed residential and small commercial

users in the highest priorities and interruptible, large-volume, industrial users in the lowest, first-curtailed priorities.

Several considerations shaped FPC's approach to the curtailment priority system: first, the importance of gas used to protect health, safety, and other human needs; second, the operational difficulty of physically cutting off or reducing service to residential and small commercial customers; third, the differences in the costs that different kinds of end-users would experience in converting to an alternate fuel.

This review and rulemaking process will implement the provisions of the NGPA that mandate the establishment of certain curtailment priorities. Additionally, the rulemaking provides an opportunity for review of gas curtailment priorities, adopted by the FPC in 1973, in light of current circumstances and requirements.

Specifically, the review of curtailment priorities has focused on the following:

(1) High priority and essential agricultural uses. Section 401 of the NGPA requires the Secretary of Energy to prescribe a rule restricting interstate pipelines from curtailing the requirements of "high priority users" (e.g., schools, hospitals, residences) and of essential agricultural uses that the Secretary of Agriculture has certified as necessary for full food and fiber production. Essential agricultural uses may be curtailed only to meet needs of "high priority users" or when FERC determines in consultation with the Secretary of Agriculture that an alternate fuel is economically practicable and reasonably available. DOE has previously issued a rule implementing these priorities (see CFR Part 580, 44 FR 15642, March 15, 1979). DOE anticipates that the substance of that rule will be incorporated into the present rulemaking.

(2) Industrial process and feedstock uses. Section 402 of the NGPA directs the Secretary of Energy to prescribe a rule limiting the circumstances in which an interstate pipeline may curtail gas supplies used in an industrial process or as a feedstock. Use as a feedstock refers to gas employed as an ingredient of the end-product, as distinguished from gas used to power production machinery.

(3) Emergency allocation authority. Relevant sections of the National Energy Act (NEA) authorize the President to declare a natural gas supply emergency, which could trigger various consequences. As an example, the President could authorize an interstate pipeline to make emergency purchases from intrastate pipelines under short-term contracts. This authority, while outside the scope of the curtailment priority system itself, must work in concert with it. Therefore, this rule will consider the effects of the NEA emergency authorities on the curtailment priority system. Decontrol of natural gas prices will not affect the curtailment priorities established by this rule.

Alternatives Under Consideration

(A) Maintain a system similar to the present system as developed by the FPC, while making those changes required by the NGPA and improving the present system by facilitating free flow of gas between systems. As compared to making no change in the present system, this alternative would have economic effects on the order of magnitude of $1 billion. These effects would be offset by $0.9 billion, which is the estimated cost of establishing the essential agricultural priority required by the NGPA. If the present system is also improved by allowing a "percentage limitation" option, i.e., allowing lower priorities not to be curtailed completely before a higher priority is curtailed, this would provide further reduction in the cost of the curtailment system. The net benefit of this alternative would be on the estimated order of magnitude of $1.2 billion ($1 billion plus $1.1 billion minus $0.9 billion).

The present curtailment system also has the advantage of being familiar to both gas suppliers and users, which would minimize the uncertainty that could otherwise lead to additional costs if the system were changed and could offset most of the benefits of a newer and more complicated system such as a "pricing" system. However, a pricing system could allocate natural gas to users more precisely on the basis of cost benefit analysis.

(B) Develop a curtailment system as in alternative (A), but updating the base period from which requirements are measured. Systems using a fixed base period instead of rolling or updating the base period are likely to cause increases in shortages costs if they switch to another fuel under the present Federal curtailment approach. A rolling base period involves updating the index of gas requirements from which curtailments are measured. In rolling the base period, the total supply of gas available to all distribution companies served by a pipeline would not be affected, but the supply would be reallocated in proportion to the current end-use profiles of the pipeline distribution companies' customers which may have changed over time.

Although this updating process may give a more current picture of the end-use of the gas delivered, it would increase the costs of curtailments by about $0.2 billion per year, if there were a complete shift to a rolling base period in the present Federal plans. Suppliers and users have instigated self-help measures obtaining their own supplies of gas under the present curtailment system, and the cost of disrupting these self-help projects would most likely offset any benefits derived from the updating process.

(C) Develop a pro-rata system that reduces all users' deliveries by a percentage equal to the percentage of supply reduction. It is tempting to think that the apparent fairness of pro-rata curtailment justifies this alternative and that users with low conversion costs would switch to another fuel, allowing a gradual evolution to an optimal curtailment system based on pro-rata allocation, but this is not the case. Unfortunately, switching to a pro-rata system would destroy good parts of the present system and eliminate the benefits from users who have already adjusted to curtailments under the present system.

The present FERC curtailment policy provides for pro-rata allocation within each priority category. Since the present categories have been formed by an end-use system that does recognize differences in shortage costs, a full pro-rata plan is bound to increase costs. It will lump all users into one category even though surveys show that there are widely different costs. The 1976–1977 shortage had impact costs of $54/Mcf (thousand cubic feet) of shortfall in higher priorities and only $2/Mcf in lower priorities. Pro-rata is less precise than the end-use approach in present curtailment plans for identifying uses which have high costs of conversion to other fuels.

In addition to causing higher shortage costs, pro-rata is not practical and not in accordance with new legislation. For example, pro-rata cannot be applied to residential and small commercial users for operational reasons. It cannot be applied to "agricultural uses" and "essential industrial process or feedstock uses" because of stipulations in the NGPA.

Weather and price controls combined create shortages that cause high shortage costs under pro-rata. There are high costs of fuel switching, and there are high impact costs for users who cannot justify fuel substitution. Even when feasible, fuel substitution is expensive when the investment is only for infrequent shortages.

(D) Use some form of "pricing" or bidding approach to distribute available gas supplies during periods of curtailments instead of a rationing system, e.g., end-use customer bidding for available gas supplies. Fuel substitution costs vary greatly, even among users within the same carefully designed end-use priority categories; precise ranking of users in line with substitution costs may not be possible except under some type of pricing approach. Surveys reveal that substitution costs range from $2/Mcf to $20/Mcf even within one end-use category, as presently constituted; in addition, shortage impact costs range from $0.10/Mcf to $100/Mcf among users within one end-use priority class due to large impacts as curtailment reaches 100 percent.

To be practical, a pricing system must be implemented at the end-user level. This would involve changes in concepts for State regulation and would require distribution company participation. There appears to be no practical implementation plan for a pricing system with present Federal constraints and using only interstate pipeline participation.

Additional studies are necessary to determine if a practical pricing approach could be developed and whether it could attain most or all of the $3.6 billion savings estimated in our Regulatory Analysis as the net national benefit of switching from the present system to some type of pricing system. These studies could also determine if implementation of a pricing approach would have significant costs that might affect the annual gains. A thorough study of a pricing approach prior to any major change in curtailment policy would be valuable for outlining the best long-run solution to managing natural gas curtailments.

We are also considering whether the guidelines should apply strictly to all interstate pipelines which transport gas, or whether FERC should be allowed to depart from strict application of the general policy under the ERA rule to account for the differing circumstances of individual pipelines, making adjustments where they are necessary. Individual pipelines vary as to number and types of customers and suppliers of gas, as well as to the conditions under which they operate, such as weather conditions in their particular service areas.

The present Federal approach to curtailment priorities is based on end-use; it reflects costs of substitution and has the benefit of being familiar to suppliers and users after years of operation. NGPA mandates some changes in priorities, but no further changes are warranted because benefits will not justify the greater costs and uncertainty from changing priorities. However, there are worthwhile modifications that can be made to the overall functioning of the present system. For example, the total costs of natural gas curtailments could be reduced if priority systems and natural gas policies in general could encourage freer flow of gas from users with low costs of fuel substitution to users with high costs of substitution.

The proposed rule concerns all priority-of-service categories related to curtailment of natural gas deliveries by interstate pipeline companies. The rule is consistent with the majority of the comments responding to our Notice of Inquiry (NOI) and the findings of our Regulatory Analysis, and adopts in substance our previously issued final rule regarding essential agricultural uses. Priorities established by the proposed rule, with Priority One to be the last curtailed, are as follows:

(1) High-priority, which includes residential, small commercial (less than 50 Mcf on a peak day), schools, hospitals, plant protection, and institutions such as prisons.

(2) Essential agricultural uses, certified by the Secretary of Agriculture, without alternate fuel capability.

(3) Essential industrial process and feedstock uses as defined by the proposed rule, without alternate fuel capability.

(4) All gas use less than 300 Mcf per day not included in Priorities One through Three, including large commercial users.

(5) All other users not included in Priorities One through Four, with volumetric subcategories, i.e., larger users would be curtailed before smaller users.

The first three priorities are defined in accordance with the language in Title IV of the NGPA and our final rule governing priorities for essential agriculture use. The 300 Mcf per day cutoff level of Priority Four is based on comments from the NOI indicating that it is logistically almost impossible to curtail such uses on a short-term basis. These uses may be presumed not to have alternate fuel capacity.

The rule provides more flexibility for priority categories Four and Five by providing that curtailment of volumes within any priority category or subcategory below the statutorily mandated categories (Priorities One, Two, and Three) may be limited to some percentage of the total requirements in circumstances where such treatment would reduce shortage costs (i.e., cost of substitute fuels, lost production, etc.) and where more precise end-use priority classification is not possible. Imprecision in present curtailment plans might be reduced in two ways. First, individual suppliers and users could more precisely classify uses within the base period requirements for each priority category. Second, a Federal rule could give higher priority to more critical volumes within categories, e.g., by establishing subdivisions within intermediate priorities, such as the "percentage-limit" option. Priority Five is subdivided into volumetric ranges for requirements over 300 Mcf per day based on findings in the Regulatory Analysis that large users have lower curtailment costs per unit of gas.

The proposed rule should give the FERC ample flexibility to take into consideration a pipeline's specific circumstances in implementing the rule.

While the proposed rule sets out a curtailment priority system which the comments to our NOI and our draft Regulatory Analysis say should reduce the overall national costs of curtailments, other costs from implementing changes for the sake of change may outweigh any benefits. To prevent this, the proposed rule states that "nothing requires that a curtailment plan in effect on the date of the adoption of this rule be changed, except to the extent that changes are necessary to protect Priorities One, Two, and Three from curtailment."

Summary of Benefits

Sectors affected: General public.

Any reduction in the economic costs of curtailments under improved curtailment options helps to reduce the inflationary effects that would otherwise result from cost increases stemming from delayed production and from shifting production among producers. Studies and analysis show that the net macro-economic effect of using any alternative that reduces curtailment costs is a reduction in the amount of inflation equal to the reduction in total costs resulting from the use of such alternative.

Summary of Costs

Sectors affected: Interstate pipelines; natural gas distribution companies; low priority direct users of natural gas, such as large-volume industrial or electric utility users; high priority users, such as residential users; customers of industrial users and electric utilities; and the general public.

The selection of a curtailment option has significant effects on real Gross

National Product. Curtailment impacts on gas users are offsetting because any permanently lost production of goods and services by a curtailed end-user is made up by other establishments, and temporarily lost production is made up later by the same end-user. Surveys of redistribution of services indicate that this is usually not a problem because of the short duration of critical gas shortages.

The following types of costs have been analyzed:

(1) Users' shortage impact costs: These are all users' costs that can be attributed to a specific shortage of natural gas, e.g., the higher costs of substitute fuels, cost of interrupted production and unemployment.

(2) Users' shortage coping costs: These are all users' costs to prepare for natural gas curtailment whenever it might occur, e.g., the investment costs of having dual-fuel capability to prevent interrupted production during curtailment.

(3) Suppliers' operating costs: All costs that pipeline and distribution company suppliers incur to supply and allocate gas, e.g., the cost of maintaining underground storage, liquefied natural gas, propane storage to meet sharp peaks on abnormally cold days, and the cost to operate in a spot market during potential shortages.

(4) Non-users' pollution costs: The costs of different pollution levels, e.g., the additional pollution damage when dirtier fuels are substituted for natural gas.

For example, the "users' shortage impact costs" that could result from doing nothing about the present curtailment system are estimated to be on the order of magnitude of $4 billion; on an overall national basis the "user shortage coping costs" are $1.6 billion, and the "suppliers' operating costs" are $18 billion, or a total of $23.6 billion (1978 dollars). These same costs for a system based on a pricing approach which is integrated with rate design structure is estimated to have total costs of $20 billion. The result of using a pricing approach could theoretically reduce costs by $3.6 billion ($23.6 billion less $20 billion). These costs represent the willingness to pay to avoid curtailments. These costs are based on simulations of day-to-day management of curtailments in the face of uncertain weather. Shortage costs are the average for all types of weather that could occur. The studies of "non-user pollution costs" indicate a negligible cost change between the alternatives for changing the present rationing approach and doing nothing, and an uncertain gain if some type of pricing approach is used.

The result of case studies indicated there would be little change in environmental impacts from the status quo of any of the curtailment alternatives. The impacts of all alternative curtailment policies on annual pollutant concentrations were nearly identical to the impact of existing curtailment policy. The net effect, therefore, of any change from the status quo was essentially zero. This is explained in major industrial areas by the fact that large quantities of emissions from other sources in these major industrial areas completely overshadow the emissions from the burning of alternate fuels during periods of winter season natural gas curtailment.

Exceptional cases of larger incremental increases in pollutants can be dealt with on a case-by-case basis. The FERC currently has authority to grant exemptions from a given curtailment policy if it finds that undue hardship otherwise would result. The Draft Environmental Impact Statement therefore recommends that the FERC continue environmental reviews of individual pipelines for the purpose of evaluating requests for exemptions from applicable curtailment rules.

Related Regulations and Actions

Internal: "Curtailment Priorities for Essential Agricultural Use," final rule issued on March 9, 1979 (44 FR 15642).

"Emergency Natural Gas Regulations" (under consideration).

External: FERC—Rules issued under Title III of the NGPA.

FERC and Department of Agriculture—Rules issued under Title IV of the NGPA.

Active Government Collaboration

The Federal Energy Regulatory Commission staff is kept informed of Economic Regulatory Administration activities. The Commission is formally reviewing the DOE-ERA rule, as provided in § 404 of the DOE Act. ERA and FERC held four joint meetings on this NPRM in July and August 1980 (Chicago, Atlanta, San Francisco, and Washington, DC).

Timetable

Final Rule—December 1980.
Final Rule Effective—Immediately on publication in the **Federal Register**.

Available Documents

Final Rule—"Curtailment Priorities for Essential Agricultural Uses," Docket No. ERA-R-78-22 (44 FR 15642, March 15, 1979).

NOI—"Concerning Review of Natural Gas Curtailment Priorities," Docket No. ERA-R-79-10 (44 FR 16954, March 20, 1979).

NOI—"Concerning Use of Natural Gas Authorities to Increase Coal and Other Non-Petroleum Fuel Usage and Heavy Oil Production," Docket No. ERA-R-79-49 (44 FR 61243, October 24, 1979).

NPRM—45 FR 45098, July 2, 1980, and related Regulatory Analysis and Environmental Impact Statement.

Public comments on the above.

All documents are available in the DOE Freedom of Information Reading Room, Forrestal Building, Room GA-142, 1000 Independence Avenue, S.W., Washington, DC 20585.

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DOE-ERA

Powerplant and Industrial Fuel Use Act of 1978; Cogeneration Exemption (10 CFR Parts 500*, 503*, 504*, 505*, and 506)

Legal Authority

Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*; Powerplant and Industrial Fuel Use Act of 1978, 42 U.S.C. § 8301 *et seq.*; E.O. 12009.

Reason for Including This Entry

The Department of Energy (DOE) believes that this rule is important because it will establish a statewide energy limit as a means of encouraging cogeneration in regions where there is a potential for oil and gas savings, while insuring that new alternate fuel-fired capacity will not be deferred.

Statement of Problem

Under the Powerplant and Industrial Fuel Use Act of 1978 (FUA), new and existing powerplants and major fuel burning installations (MFBIs), including cogenerators (electric powerplants or major fuel burning installations that produce electric power and any other form of useful energy, such as steam, gas, or heat, which is or will be used for industrial, commercial, or space heating purposes), are prohibited from using oil and natural gas, unless the Economic Regulatory Administration (ERA) grants an exemption for such uses (see 45 FR 36871, May 30, 1980). The purpose of this prohibition was to conserve our supplies of oil and of natural gas (at the time the Act was passed, natural gas was in

short supply) and to encourage the use of other fuels. Sections 212(c) and 312(c) of the Act specifically provide for exemptions for oil and natural gas use in eligible new and existing cogenerators.

ERA adopted interim rules relating to exemption for cogeneration facilities on May 17 and July 23, 1979 (44 FR 28950 and 44 FR 43176, respectively). After reviewing the comments on the interim rules, ERA determined that before it adopts a final rule on cogeneration, it would be appropriate to propose and solicit public comment on other methods of implementing the cogeneration exemption sections of FUA.

Therefore, ERA is proposing a new approach in an NPRM that encourages cogeneration in those regions of the country where there is a potential for oil and gas savings, while insuring that new alternate fuel-fired capacity would not be deferred. This approach proposes three methods for qualifying for a cogeneration exemption: (1) a showing of overall oil/gas savings through the use of cogeneration, including a demonstration that new coal- or nuclear-fired facilities will not be delayed as a result of cogeneration; (2) a state certification that a cogenerator is to receive an "allocation" of cogeneration capacity (states would be allowed to grant allocations up to a limit set by ERA, to assure that cogenerators displace only oil- or gas-fired electric utility powerplants); or (3) a showing that the exemption would be in the public interest.

In addition, ERA is seeking public comments on a proposal to amend the current definition of "electric generating unit" to avoid the possible unintended treatment of certain cogenerating MFBIs as powerplants and, thus, perhaps inhibit cogeneration which would otherwise be economically efficient.

Alternatives Under Consideration

A. Electric Generating Unit.

ERA seeks comment on whether the dividing line between MFBIs and powerplant cogenerators should be "half the useful energy output" or some other percentage.

ERA is also proposing an alternative definition of an electric generating unit: "Electric generating unit" does not include (1) any "electric generating unit" subject to the licensing jurisdiction of the Nuclear Regulatory Commission; and (2) any cogeneration facility, less than half of the annual electric power generation of which is sold to or exchanged with an electric utility for resale by the utility to consumers other than the cogenerating supplier.

Our proposed definition would only refer to net electrical power sold or exchanged for resale; it would not include amounts sold to the grid but repurchased by the cogenerator firm for its own use. This concept could also be adopted in the primary proposal, adding the word "net" before "annual electrical power generation" in the second exception. ERA has reservations about whether this definition is permitted under FUA. We are not yet persuaded that it is appropriate, since it could result in increases in oil and gas prices which are currently below market clearing prices. Moreover, it could result in the deferment of baseload alternate fuel-fired electrical generating capacity. We solicit comments whether either of the alternative definitions is appropriate, as well as the impact they may have with respect to the development of energy efficient cogeneration and on future alternate fuel use for electrical generation.

ERA also solicits other appropriate methods of distinguishing MFBIs and powerplant cogenerators and their impact on cogeneration and future oil and gas use.

B. Cogeneration Exemption: Alternative Proposal for States Using Oil and Gas for Baseload Electrical Cogeneration.

ERA seeks comment on an alternative proposal for determining eligibility for cogeneration exemptions in those states in which there are a significant number of existing oil/gas-fired baseload powerplants.

In this proposal, ERA has assigned to each of the oil/gas-dependent states an initial "Cogeneration Electric Capacity Limit" consisting of a total megawatt output instead of a total energy input as described in the primary proposal. Under this approach, the limit is focused solely on the electrical generation by the cogenerator and does not include the nonelectric output (e.g., industrial steam, heat, etc.).

Summary of Benefits

Sectors Affected: Potential industrial and electric powerplant cogenerators; and the general public.

Any of the alternative proposals should increase the amount of cogeneration. Without modification to the FUA jurisdictional facilities or modification to the exemption provision for cogenerators, the oil and gas savings which could be achieved by use of this technology might be lost.

Summary of Costs

Sectors Affected: The general public.

Certain industrial and electric powerplant facilities which could have used coal or other alternate fuels might instead use oil and gas in cogeneration facilities if the prohibitions and exemptions applicable to such facilities are relaxed.

Related Regulations and Actions

Internal: "New Electric Powerplants and Certain New Major Fuel Burning Installations; Use of Petroleum and Natural Gas" (45 FR 38276, June 6, 1980). "Calculation of Cost of Using Alternate Fuels under the Powerplant and Industrial Fuel Use Act of 1978" (45 FR 42190, June 23, 1980). "Powerplant and Industrial Fuel Use Act of 1978; Existing Facilities" (45 FR 53682, August 12, 1980).

External: Public Utility Regulatory Policies Act of 1978 (45 FR 12214, February 25, 1980, and 45 FR 17959, March 20, 1980).

Active Government Collaboration

None.

Timetable

Final Rule—End of calendar year, 1980.

Final Rule Effective—30 days after issuance.

Available Documents

NPRM—45 FR 53368, August 11, 1980.

All documents (including public comments in response to the NPRM and comments from public hearings held September 25, October 6, and October 9, 1980) are available in the DOE Public Information Office, Room B110, 2000 M Street, N.W., Washington, DC 20461.

Agency Contact

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DOE—Resource Applications

Outer Continental Shelf (OCS) Sequential Bidding Regulations (10 CFR Part 376)

Legal Authority

Department of Energy Organization Act, §§ 302(b)(1) and 303(c), 42 U.S.C. §§ 7152(b)(1) and 7153(c); and the Outer Continental Shelf Lands Act, as amended, § 8(a)(1), 43 U.S.C. § 1337(a)(1).

Reason for Including This Entry

This entry is included because sequential bidding would improve the competitive position of smaller firms for OCS oil and gas leases.

Statement of Problem

The present cash bonus-fixed royalty bidding system for Outer Continental Shelf (OCS) leases requires the Federal Government to offer all drilling areas (tracts) included in an OCS lease sale to bidders at the same time. All bids must be sealed and accompanied by one-fifth of the cash payment the bidder intends to pay for the lease (cash bonus). Bids are opened, announced publicly, and recorded, but no bids are accepted or rejected, and no leases are awarded at that time. Within 60 days of the opening of bids, the Department of the Interior (DOI), which administers this program, decides whether to accept the bid from the highest qualified bidder for each tract. Bids that DOI does not accept within the 60-day period, it rejects. DOI returns the money that was deposited on rejected bids.

The present bid opening system requires a substantial commitment of cash resources by firms to particular OCS lease sales; this may strain the ability of some firms to participate in the OCS leasing process. Bidders must be prepared to support each bid immediately with a deposit of one-fifth of the total cash payment. Opening all the bids at the same time may limit the number and magnitude of bids that an individual firm is able to submit. In addition, a firm might win on a greater number of tracts in an OCS lease sale than it had anticipated, which could call for bonus payments that exceed the firm's financial resources, forcing it to search for additional sources of capital.

The Department of Energy (DOE) estimates that more than 100 smaller firms are more subject to constraints of this type than larger firms. Some small companies may have withdrawn from competition for tracts because of financial barriers. In addition, the simultaneous nature of the bidding process may tend to preserve an informational advantage that larger firms may have over smaller ones because they can afford more extensive exploration in advance of a lease sale.

Under § 302(b)(1) of the Department of Energy Organization Act, DOE has authority to promulgate regulations which foster competition for Federal leases, to assure the public a fair return on its resources. Thus, DOE is interested in alternative bidding mechanisms which may improve the ability of smaller companies to compete in these lease sales.

Sequential bidding would address these problems by dividing an OCS lease sale into at least two bidding sessions, separated by a minimum of 48 hours. Tracts would be assigned to bidding sessions through a random selection procedure; bidding sessions each would consist of an approximately equal number of tracts. Cash bonus deposits accompanying the highest bid on each tract would be retained by DOI until it made a decision on awarding leases. DOI would return all other cash bonus deposits to the bidders that submitted them immediately after the conclusion of each bidding session. Arrangements for disclosure of bids are presently being discussed within DOE and DOI; they include no information release, announcement of the highest bidder, and disclosure of all bidders and amounts of bids at the end of each bidding session.

Alternatives Under Consideration

Possible alternatives to sequential bidding which we have been considering include a "bid limit" option, which would allow bidders to set a "maximum aggregate winning cash bonus limit" for the lease sale. This would enable a firm to bid on tracts with the assurance that its winning bids would not exceed an amount which it had stipulated.

Another possible approach that might achieve results similar to sequential bidding would be to hold lease sales at shorter intervals, each sale with approximately the same number of tracts. However, in order to reduce a bidder's financial exposure as effectively as we think sequential bidding could do, 18 to 24 lease sales would be necessary each year compared with five to six lease sales now being held annually. The administrative burdens on DOI associated with this alternative would be severe.

Retention of the present bid opening system is another alternative. This alternative would preserve a maximum degree of simplicity in administrative matters, but would not address the problems we have discussed above.

DOE has proposed that sequential bidding be tested on an experimental basis. This will allow bidders to become familiar with the process, and allow DOE and DOI to study bidder reactions. This experimental approach is an innovative alternative to an immediate move to an unproved new bidding process.

Summary of Benefits

Sectors Affected: Off-shore oil and gas extraction (including independent producers, joint business ventures, and other firms participating in offshore operations), particularly small firms; and the general public.

DOE expects sequential bidding to foster competition for Federal OCS leases, partially by easing financial barriers to participation, and partially by reducing informational advantages that major OCS participants currently have. Returning cash bonus deposits of unsuccessful bidders after each session would allow them to use returned funds in the subsequent bidding session. Announcing the amount of the high bid for each tract will provide information on the value other bidders have placed on tracts as a result of their exploration. These changes will tend to equalize the informational and financial position of smaller firms participating in leasing competition.

DOE estimates that the application of sequential bidding to an OCS lease sale would yield greater revenue to the Government because of increased competition for OCS leases.

The use of sequential bidding primarily affects current and prospective bidders for OCS leases. DOE anticipates that smaller firms would benefit more from sequential bidding than would the major participants in OCS lease sales.

Summary of Costs

Sectors Affected: DOE; and DOI.

The use of sequential bidding imposes a relatively minor administrative cost on DOE and DOI in performing additional analyses and extending the actual conduct of the sale over a minimum of three days.

Related Regulations and Actions

Internal: Final OCS bidding system regulations, published at 45 FR 9536, February 12, 1980 and 45 FR 36784, May 30, 1980 (10 CFR Part 376).

External: Current OCS lease sales bidding procedures, administered by the Department of the Interior, found at 43 CFR 3300.

Active Government Collaboration

Department of the Interior. The Department of Justice and the Federal Trade Commission are advising on competition issues.

Timetable

Final Rule—First quarter, 1981.
Final Rule Effective—60 days after it is issued.

Available Documents

Draft Regulatory Analysis, "Increasing Competition for Federally-Owned Mineral Fuels by Altering the Present Bidding Process to Allow for Sequential Bidding" (September 2, 1979).

NPRM—44 FR 52842, September 11, 1979.

Public comments in response to NPRM, and comments from public hearing (October 15, 1979).

All documents are available in the DOE Freedom of Information Reading Room, Room GA-142, Forrestal Building, 1000 Independence Avenue, S.W., Washington, DC 20585.

Agency Contact

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DOE-RA

Proposed Regulations Establishing Alternative Bidding Systems for Coal Lease Sales

Legal Authority

Department of Energy Organization Act, §§ 302(b)(2) and 303(c)(1), 42 U.S.C. §§ 7152(b)(2) and 7153(c); Mineral Lands Leasing Act, §§ 2(a), 7(a), and 32, 30 U.S.C. §§ 201, 207, and 189; and the Mineral Leasing Act for Acquired Lands, §§ 3 and 10, 30 U.S.C. §§ 352 and 359.

Reason for Including This Entry

The Department of Energy (DOE) includes this entry because it increases competition for Federal coal leases, thereby encouraging the development of coal resources in an efficient and timely manner.

Statement of Problem

On August 4, 1976, Congress enacted the Federal Coal Leasing Amendments Act of 1976 (FCLAA, P.L. 94-377, 90 Stat. 1083), which amended the Mineral Lands Leasing Act of 1920 (MLLA, Act of February 25, 1920, ch. 85, 30 U.S.C. § 181 *et seq.*). The legislation addressed eight major problems with the then existing Federal coal leasing program. These problems were: (1) speculation; (2) concentration of holdings; (3) inadequate return to the public; (4) need for environmental protection, planning, and public participation; (5) adverse social and economic impacts; (6) need for information; (7) need for maximum economic recovery; and (8) military lands.

Further, as a result of the 1973 oil embargo by the Organization of Petroleum Exporting Countries (OPEC) and the ensuing debate over the need for a definitive national energy policy, a National Energy Plan (NEP) was adopted and published on April 29, 1977. Objectives of the NEP included:

1. reducing dependence on foreign oil and vulnerability to supply interruptions;
2. substitution of abundant energy resources for those in short supply; and
3. expanding U.S. coal production and use.

On April 15, 1979, the President delivered his Energy Address to the Nation. On July 15, 1979, the President again addressed the Nation about energy. In his addresses, the President spoke about the Nation's energy problems and the steps that had to be taken to alleviate those problems. Among the steps listed were:

1. encouraging domestic production of energy; and
2. shifting to more abundant sources of energy.

One of the Nation's most abundant resources of energy is coal. However, there has not been general leasing of Federal lands for coal production since 1971. Under regulations published by the Department of Interior (DOI) on July 19, 1979 (44 FR 42585), Federal coal leasing is scheduled to resume, with the first sale scheduled for January 1981.

The proposed regulations address some of the above noted problems, goals, and changes in the law through establishing coal bidding systems and procedures to be used at coal lease sales. These bidding systems and procedures can be used to achieve some of the goals of the FCLAA (i.e., to discourage speculation and concentration of holdings and to ensure receipt of a fair return), the NEP, and national energy policy.

On August 4, 1977, Congress enacted the Department of Energy Organization Act (DOE Act, 42 U.S.C. § 7101 *et seq.*). Section 302(b) of the DOE Act (42 U.S.C. § 7152(b)) gave the Department of Energy a role in Federal coal leasing by transferring to the Secretary of Energy the functions of the Secretary of Interior to promulgate regulations under five statutes, including the MLLA and the Mineral Leasing Act for Acquired Lands (MLAAL) which relate to, among other things, the implementation of alternative systems and procedures for use at coal lease sales. Accordingly, DOE is proposing promulgation of these regulations pursuant to §§ 302(b) and 303(c) of the DOE Act, §§ 2(a), 7(a), and 32 of the MLLA, and §§ 3 and 10 of the MLAAL.

Alternatives Under Consideration

DOE initially proposed three alternative bidding systems: (1) cash bonus bid with a fixed royalty; (2) royalty bid with a fixed bonus; and (3) cash bonus bid with a sliding scale royalty. Also, intertract competition, a bidding procedure, was proposed in these rules. An NPRM was published in the Federal Register July 10, 1980 (45 FR 46712).

The first bidding system proposed was the cash bonus bid with a fixed royalty. Under this system, the royalty rate is fixed in advance of the sale at not less than 12.5 percent and firms bid a cash bonus (a lesser royalty rate may be allowed in the case of coal removed by underground mining operations). The highest cash bonus bid for a tract wins the lease, provided the bid exceeds a minimum level (established by the U.S. Geological Survey prior to the sale). This bidding system is the one historically used in competitive sales of Federal coal leases. This system places heavy emphasis on initial commitment of capital, although this capital commitment requirement has been somewhat alleviated by the provision for deferred payment of the bonus. However, it can discourage participation by smaller companies, which may reduce competition and limit the number of bids per tract. For these and other reasons, bidding systems using contingency (royalty or profit share) payments have received considerable attention.

The second bidding system proposal was the royalty bid with a fixed cash bonus. Under this system, the cash bonus is fixed prior to the sale (at a nominal level) and companies bid on the royalty rate that will apply if the lease is productive. Because royalty bidding deemphasizes the cash bonus, it encourages greater participation by smaller companies. There is no immediate penalty to the bidder for increasing his royalty bid. However, there is a danger inherent in this system that a bidder will increase his royalty bid in an attempt to win the lease only to find that the royalty rate is too high to permit economic development of the resource. In sum, while this system reduces initial financial requirements for engaging in the bidding process, there is a substantial risk that winning royalty bids will be "too high," and will prevent resource development for smaller or marginal reserves.

The third bidding system which DOE proposed was the cash bonus bid with a sliding scale royalty. A sliding scale royalty system also uses a cash bonus bid variable, but the royalty rate that applies for each time period is based on the value of production from the lease during the time period. Several functional relationships are available for calculating the royalty rate: linear, logarithmic, reciprocal, etc. When compared with the cash bonus and fixed royalty systems under similar conditions, the sliding scale systems

tend to reduce the expected cash bonus required to win a lease. Also, when compared to higher-rate fixed royalty systems, the sliding scale system tends to reduce the risk that smaller reserves will not be developed. The reduced cash bonuses should encourage bidding by smaller companies and could entice firms to bid on tracts that would not otherwise receive bids under the traditional systems.

No single system is invariably superior to all other systems over the wide range of economic, geological, and engineering conditions which might be experienced. However, in individual sales, specific sale and tract conditions and the relative importance placed on the various (and competing) legislative and energy policy objectives will dictate the selection of an appropriate bidding system. DOE is, however, considering analyzing further the bidding systems that have as components the royalty bid with a fixed cash bonus and the cash bonus bid with a sliding scale royalty.

Under the intertract competition bidding procedure, which was also being proposed, a greater amount of tracts would be offered for lease sale than are to be leased. Bids are received on all tracts offered for lease sale and are submitted on a standard measure of value, e.g., dollars per ton. Leases are awarded to the highest bidders until the desired level of leasing is achieved, e.g., one million tons. Because only a fraction of the total tracts offered will be leased, bidders are placed in competition not only with each other for a tract, but also with the highest bidders on all tracts that are part of the lease sale. It is believed that an intertract competition procedure will increase competition in leasing and provide a means of selecting tracts for leasing. However, administrative problems may include larger lease sales, more costly environmental impact statements, and tract evaluations for a much larger number of tracts.

Summary of Benefits

Sectors Affected: The coal mining industry, and companies participating in coal lease bidding; the Federal government; and the general public.

DOE anticipates that the regulations will improve the coal leasing program. They are designed to serve several purposes:

(1) provide a fair return to the Federal Government for its resources;

(2) increase competition for Federal leases;

(3) encourage development of coal resources in an efficient and timely manner;

(4) discourage speculation; and

(5) discourage concentration of holdings.

In addition, they will carry out the intent of the DOE Organization Act, the Mineral Lands Leasing Act, and the Mineral Leasing Act for Acquired Lands, because they will foster competition and implement alternative bidding systems for Federal leases. The public will also benefit if the revised bidding system regulations do a better job of meeting the stated objectives.

Summary of Costs

Sectors Affected: Companies participating in coal lease bidding; and DOI.

DOE anticipates no significant additional costs as a result of this regulation. Administrative costs may increase slightly if the intertract competition bidding procedure is used. Also, the Department of the Interior has indicated that the U.S. Geological Survey, prior to actual use of a sliding scale royalty in a lease sale, will analyze the administrative costs associated with that system.

Related Regulations and Actions

Internal: Coal production goals which have been developed by the Leasing Policy Development Office and which are currently being updated to reflect synfuels development.

External: Regulations of the Department of the Interior regarding coal leasing, 43 CFR Part 3500.

Active Government Collaboration

The Department of the Interior and the Department of Justice.

Timetable

Final Rule—December 15, 1980.
Final Rule Effective—January 1, 1981.

Available Documents

NPRM—45 FR 46742, July 10, 1980.
Public Comments on NPRM.

We have prepared a Regulatory Analysis entitled "Coal Bidding Systems Regulations," and it is available, along with the proposed regulation, from the Agency Contact listed below.

All documents are available in the DOE Freedom of Information Reading Room, Forrestal Building, Room GB-142, 1000 Independence Avenue, S.W., Washington, DC 20585.

Agency Contact

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DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

Office of the Secretary

Solar Energy and Energy Conservation Bank (24 CFR 1800 et seq.)

Legal Authority

The Energy Security Act, Title V (The Solar Energy and Energy Conservation Act of 1980), P.L. 96-294, June 30, 1980.

Reason for Including This Entry

The Department of Housing and Urban Development (HUD) includes this entry because it is a precedent-setting action in the area of energy conservation, with expected economic effects considerably in excess of $100 million per year, and because it is of considerable public interest.

Statement of Problem

The purpose of the Solar Energy and Energy Conservation Act is to encourage investments in energy conservation and solar energy and thereby reduce the Nation's dependence on foreign oil. The Solar Energy and Energy Conservation Bank (henceforth "Bank") is to be established as a separate entity within the Department of Housing and Urban Development to attain the objectives of the Act by providing subsidies covering a portion of the cost of energy-related investments, with the remainder of the cost financed through conventional channels.

Alternatives Under Consideration

Currently, tax incentives form the bulk of government aid to solar energy and energy conservation investments. While many taxpayers have taken the "energy credits" on their federal income tax returns, most of the impact has been on middle and upper income taxpayers. The Act provides for a new system of direct Federal grants to purchasers of energy-saving equipment to cover a portion of the investment. The remainder of the cost is financed through conventional channels. Subsidies and program requirements differ between the energy conservation program and the solar energy program, so that while there is some similarity of approach, the programs and the alternatives under the programs should be considered separately. While there are many program design alternatives, the Regulatory Analysis will focus on (1) the eligibility of program participants (Congress specified a schedule relating family income to the allowable subsidy, and the main question here is which income groups should obtain subsidies), (2) the eligibility of solar and energy

conservation investments for funding (that is, which kinds of equipment are eligible, with what technical specifications), and (3) the amount of subsidy allowable for each project.

Summary of Benefits

Sectors Affected: Building contractors; owners and tenants of residential buildings; commercial buildings not primarily used for manufacturing; certain agricultural buildings; banks and credit agencies; manufacturers of solar energy equipment; and the general public.

Estimates of aggregate benefits from the Regulatory Analysis are not yet available, but our preliminary estimate is that the program will be cost effective, with benefits exceeding costs. The Regulatory Analysis (under preparation) should allow for much more refined benefit and cost estimates which vary across program alternatives.

Qualitatively, building contractors will benefit from increased numbers of conservation investments, and banks and credit agencies will benefit from higher loan demand. Owners of buildings will be assisted in making investments which will lower heating and cooling costs for their buildings. This in turn will generate a lower demand for energy, and hence a lower demand for imported oil. We expect the solar energy program to stimulate the solar equipment manufacturing industry and provide a large scale demonstration of the feasibility of solar improvements in many sections of the United States.

Summary of Costs

Sectors Affected: The Federal Government, primarily HUD.

Overall program authorization calls for HUD to provide $200 million, $625 million, $800 million, and $875 million in fiscal years 1980 through 1983, respectively, for the purpose of grants under the energy conservation program. Authorizations for solar energy systems are $100 million, $200 million, and $225 million in fiscal years 1980 through 1982. Any program of this magnitude involves start-up costs and costs of administering the program. We have taken steps to minimize these costs in the program design, and minimize the compliance costs of those eligible for program participation.

Related Regulations and Actions

Internal: None.

External: DOE regulations governing other parts of the Energy Security Act.

Active Government Collaboration

The Board of Directors of the Bank will consist of the Secretary of Housing and Urban Development, the Secretary of Energy, the Secretary of the Treasury, the Secretary of Agriculture, and the Secretary of Commerce.

Timetable

NPRM—None.
Interim Rule—December 1980.
Public Comment Period—60 days following publication of Interim Rule.
Draft Regulatory Analysis—Will accompany Interim Rule.
Final Rule—July 1981.
Final Regulatory Analysis—Will accompany Final Rule.

Available Documents

None.

Agency Contact

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DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

Fuel Economy Standards for Model Year 1983-85 Light Trucks (49 CFR Part 533*)

Legal Authority

Motor Vehicle Information and Cost Savings Act, § 502(b), 15 U.S.C. § 2002.

Reason for Including This Entry

The National Highway Traffic Safety Administration (NHTSA) thinks this rule is important because of its impact on the automotive industry, the public, and energy consumption.

Statement of Problem

In 1978, roughly half of the total petroleum consumed in the United States was used for transportation. The light truck fleet, which includes vehicles such as conventional pickups and vans, consumed approximately 20 percent of that amount. During the past 10 years, light truck sales have grown dramatically. Sales recently have declined, in part because of the poor gasoline mileage of these vehicles and the rising price of gasoline. Nevertheless, we expect light trucks to account for 20 percent of all vehicle sales annually because of the demand for multi-use vehicles. Such sales mean that light trucks will continue to consume substantial amounts of fuel.

Congress set fuel economy standards for passenger cars for model years 1978 to 1980 and 1985 and thereafter, and directed NHTSA to establish standards for model years 1981 to 1984. Congress also directed NHTSA to establish standards for light trucks for each model year beginning with 1979. Without fuel economy standards for light trucks, the gap between the improving fuel efficiency of passenger cars and the low fuel efficiency of light trucks would widen, contrary to the national objective of fuel conservation. In response to the Congressional mandate of Title V, Improving Automotive Efficiency, of the Motor Vehicle Information and Cost Savings Act (the Act), NHTSA already has established fuel economy standards for light trucks in the 1979 to 1982 model years. NHTSA published the 1982 model year standard in the **Federal Register** on March 31, 1980 (45 FR 20871) and has proposed that standards be established for 1983 to 1985.

Alternatives Under Consideration

The final fuel economy standards for light trucks for model years 1983 to 1985 must satisfy the statutory criterion for maximum feasible average fuel economy and must reflect consideration of technological feasibility, economic practicability, the impact of other Federal standards for motor vehicles, and the Nation's need to conserve energy. Based on the results of the Agency's preliminary Regulatory Analysis, we have proposed the following ranges of possible fuel economy improvement for 1983 to 1985 model years.

Proposed Fuel Economy Standards for Light Trucks in 1983-85 Model Years

Model year	Vehicle miles per gallon (mpg): Two wheel drive	Vehicle miles per gallon (mpg): Four-wheel drive
1983	18.0-20.0	15.6-18.0
1984	18.8-21.4	16.1-19.3
1985	19.7-22.4	16.2-19.9

NHTSA is also considering the possibility of a combined two-wheel drive and four-wheel drive standard. This would provide additional flexibility to the manufacturers in terms of where to make investments and and how they want to meet the standard.

Summary of Benefits

Sectors Affected: Buyers of new light trucks; the general public; and suppliers of materials and components that improve fuel efficiency.

NHTSA estimates that the new fuel economy standards for model year 1982 light trucks and the standards proposed for light trucks in the 1983 to 1985 model years will save between 11 billion and 17 billion gallons of gasoline more than the standards for model year 1981 light trucks. The Nation could save between $3.5 billion and $5.1 billion in 2005 (at the July 1979 price of $23 per barrel for imported oil). The buyer of a 1985 model year truck meeting the proposed fuel economy levels would save between $510 and $1,120 (1979 dollars) over the life of the vehicle, compared to a buyer of a truck meeting the 1981 model year standards. Components for new vehicles, such as computerized controls to improve engine efficiency, may be installed. Thus, there would be greater demand for these items.

Summary of Costs

Sectors Affected: Manufacturers of light trucks; suppliers of materials and components which reduce energy efficiency; buyers of new light trucks; petroleum production and refining; and State and local governments.

NHTSA is developing detailed information on the costs associated with these fuel economy standards. Based on preliminary information, the Agency estimates that the average retail price of a model year 1985 vehicle, compared to a model year 1981 vehicle, would increase by $350 to $615 (1979 dollars) per vehicle. However, the two major economic issues in this rulemaking are the marketability of new, more fuel-efficient models and the financial capability of the industry to produce these new models.

The general economic effect would probably be as follows. Vehicle manufacturers would incur increases in capital expenditures and variable manufacturing costs to implement technologies for fuel efficiency. The absolute amount of such increases depends upon the level of the standards. We expect costs to range from $3.9 billion to $4.3 billion (1979 dollars). Material suppliers would experience changes in demand. For example, the substitution of aluminum for steel would increase the demand for aluminum and reduce the demand for steel. The petroleum industry would face a reduced increase in demand for gasoline. State and local governments would face a lower rate of increase in revenue from gasoline taxes due to a decrease in the rate of growth of the demand for gasoline. The initial purchase price of light trucks may increase due to potentially higher manufacturing costs.

NHTSA does not anticipate that the standards will have a significant effect on employment. The effect of the standards on the Gross National Product (GNP), inflation, and urban areas will depend directly on the price and availability of gasoline and on the level of fuel economy set in the standards.

Related Regulations and Actions

Internal: NHTSA has already issued standards for fuel economy for light trucks in model years 1979 to 1982 (49 CFR 533*).

External: The Environmental Protection Agency (EPA) has issued regulations governing how fuel economy in motor vehicles is to be measured (40 CFR 600). EPA also has issued regulations governing emissions from light trucks (40 CFR 86). The Federal Trade Commission has issued guidelines governing the advertising of fuel economy for motor vehicles (16 CFR 259).

Active Government Collaboration

NHTSA coordinates its program for fuel economy standards principally with the Department of Energy and the Environmental Protection Agency. NHTSA also reviews the program with the Council on Wage and Price Stability.

Timetable

Regulatory Analysis—Will accompany Final Rule.
Final Rule—November or December 1980.

Available Documents

NPRM—44 FR 77199, December 31, 1979.

Preliminary Regulatory Analysis.

NHTSA Docket No. FE 78-01; Notice 1.

All documents available for review in the Docket Section, NHTSA, Room 5108, 400 Seventh Street, S.W., Washington, DC 20590.

Agency Contact

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FEDERAL ENERGY REGULATORY COMMISSION

High-Cost Natural Gas Produced from Wells Drilled in Deep Waters

Legal Authority

Natural Gas Policy Act of 1978, 15 U.S.C. § 3317.

Reason for Including This Entry

This rule will encourage production of natural gas from unconventional sources by setting an incentive price for one source of such gas—gas from wells drilled in deep water. "Unconventional" or "high-cost" gas, gas produced from geologic formations or under other conditions that make it especially expensive or risky to produce, represents an important and abundant domestic energy resource and can help in our national efforts to reduce dependence on foreign fuels.

Statement of Problem

The Natural Gas Policy Act of 1978 (NGPA) placed all sales of natural gas by producers under Federal jurisdiction and set a series of gradually escalating prices for recently discovered or "new" natural gas which more closely approximated the higher costs of alternate fuels at the time the Act was passed. These prices were intended to stimulate production and to smooth the transition to deregulation of most new gas which was set for January 1, 1985 by the NGPA.

Unconventional gas, while abundant, can be discovered and produced only at extraordinary risk or cost. The Natural Gas Policy Act of 1978 (NGPA) specifies certain categories of unconventional gas eligible for an incentive price, that is, a selling price higher than the prices for conventional gas set by Congress and high enough to make recovery of this gas economically feasible. Under § 107(c)(5), the NGPA gives the Federal Energy Regulatory Commission authority to designate other categories of natural gas as unconventional.

In a Notice of Inquiry issued on June 13, 1979, the Commission requested that the public suggest categories of gas which might qualify under § 107(c)(5) for an incentive price as high-cost or high-risk gas. This rulemaking is an outgrowth of the comments received in response to the Notice of Inquiry. All commenters agreed the production of gas from submerged acreage becomes more costly as offshore production moves seaward. Costs and risks escalate rapidly because specially designed exploratory vessels, drilling and production platforms, and other equipment are required.

The purpose of this rule would be to encourage the development and production of one type of unconventional gas—gas produced from wells drilled in deep water—with an incentive price.

Alternatives Under Consideration

The Commission has proposed an incentive price of 150 percent of the otherwise applicable maximum lawful price for gas produced from water 500 feet deep or deeper. Under the proposed regulations, to qualify for the incentive price, surface drilling of the well must have been commenced on or after May 28, 1980. The Commission proposes to qualify submerged acreage in blocks conforming to the blocks leased by the Department of Interior (DOI) by reference to the 500-foot contour line on National Oceanic and Atmospheric Administration (NOAA) maps.

The Commission specifically solicited public comment on the incentive price necessary to encourage production of natural gas produced from deep water and on depth at which an incentive price becomes necessary.

The Commission is considering several alternatives. The Commission could:

(A) vary the incentive price;

(B) vary the depth at which drilling is eligible for the incentive price;

(C) establish several depths and set corresponding graduated incentive prices;

(D) take no action.

Comments on the proposed rule and continued staff analysis are expected to provide information on the relative merits of each alternative.

Summary of Benefits

Sectors Affected: Natural gas producers; natural gas users; and the general public.

An appropriate incentive price should permit producers to develop naturul gas from wells drilled in deep water on submerged acreage that has already been leased. The pace at which additional development will proceed and the additional volumes of gas that will be produced are not quantifiable. The benefits to natural gas users and the general public of increased domestic supplies of natural gas—a clean, environmentally benign fuel—and the possibility of a concomitant reduction in imports of foreign fuels are likewise not precisely quantifiable.

Summary of Costs

Sectors Affected: Natural gas producers; natural gas users; and the general public.

If the incentive price finally adopted is lower than that necessary to encourage production from deep-water wells, producers will be discouraged from recovering deep-water gas, less gas will be available to domestic consumers and we will not, therefore, be able to displace that amount of imported fuel. Conversely, if a higher than necessary price is adopted, consumers will pay unnecessarily high prices for the additional gas.

Related Regulations and Actions

Internal: The Commission is considering other categories of gas which may be eligible, as high-cost or high-risk gas, for an incentive price.

External: None.

Active Government Collaboration

The Commission worked with the Department of Interior to develop a method of designating qualified acreage.

Timetable

Final Rule—December 31, 1980.

Final Rale Effective—December 31, 1980.

Rehearing Decision—To be determined.

Regulatory Analysis—The FERC is an independent regulatory agency and is not required to prepare the Regulatory Analysis prescribed in E.O. 12044. However, the FERC performs essentially the same analysis for rules of major importance, the results of which are reported in the orders issuing NPRMs and final rules.

Available Documents

NPRM—45 FR 47863, July 17, 1980 (Docket No. RM80-38).

The comments filed on this proposed rule are available to the public at the Commission's Division of Public Information, Room 1000, 825 N. Capitol St., N.E., Washington, DC 20426.

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FERC

High-Cost Natural Gas: Production Enhancement Procedures (18 CFR Part 271, Subpart G*)

Legal Authority

Natural Gas Policy Act of 1978, 15 U.S.C. § 3317.

Reason for Including This Entry

This rule will encourage production of reserves of natural gas which are recoverable only by application of techniques to enhance production which are often too costly to apply at the prices available.

This, along with other categories of "unconventional" or "high-cost" gas, gas produced from geologic formations or under other conditions that make it especially expensive or risky to produce, represents an important and abundant domestic energy resource and can help to reduce imports of foreign fuels.

Statement of Problem

The Natural Gas Policy Act of 1978 (NGPA) placed all sales of natural gas by producers under Federal jurisdiction and set a series of gradually escalating prices for recently discovered or "new" natural gas which more closely approximated the higher costs of alternate fuels at the time the Act was passed. These prices were intended to stimulate production and to smooth the transition to deregulation of most new gas which was set for January 1, 1985 by the NGPA.

Unconventional gas, while abundant, can be discovered or produced only at extraordinary risk or cost. The NGPA specifies certain categories of unconventional gas eligible for an incentive price, that is, a selling price higher than the prices for conventional gas established by Congress and high enough to make recovery of these reserves economically feasible. Section 107(c)(5) of the NGPA gives the Commission authority to designate other categories of natural gas as unconventional.

In a Notice of Inquiry issued on June 13, 1979, the Federal Energy Regulatory Commission requested that the public suggest categories of gas which might qualify under § 107(c)(5) as high-cost or high-risk.

This rulemaking is an outgrowth of the comments received in response to that Notice of Inquiry and a petition filed by the Sun Gas Company requesting the Commission to classify gas produced as a result of production enhancement procedures as high cost. This petition was supported by other natural gas producers and environmental groups such as Friends of the Earth and the Environmental Policy Center.

Production enhancement procedures often become necessary in order to maintain or to increase production from a depleting well or a well in which production has become marginal. Production supply enhancement procedures eligible under the proposed

rule include: (1) re-entry into a well which has been plugged and abandoned; (2) re-entry into a well in order to drill deeper or start a side shaft; (3) re-perforation of the well casing or perforation into a separate gas-producing zone; (4) repair or replacement of a faulty or damaged casing or related equipment in the well; (5) acidizing, fracturing, or installation of compression equipment. Current regulations do not allow sufficient flexibility to contracting parties to amend, modify or renegotiate contracts in order to provide for production enhancement work.

The purpose of this rule is to set a ceiling or maximum price which may be paid by a purchaser and which is high enough to encourage production of reserves of natural gas recoverable only if production enhancement procedures are applied.

Alternatives Under Consideration

The Commission has proposed that gas produced with supply enhancement procedures applied after May 29, 1980 be eligible for an incentive price as high as the price for gas under § 109 of the NGPA. (In August, 1980, the price for § 109 gas was $1.72 per million Btu's.) A negotiated contract price must be in effect to ensure that the price for qualified production enhancement gas is set by agreement of all the contract parties. The Commission has also proposed a formula limiting the unit cost of production that results from enhancement procedures so that incremental revenues are not excessive.

The Commission specifically solicited comments on what constitutes a reasonable incentive price and whether other production enhancement techniques should be eligible for the incentive. The Commission also requested any information on the types of supply enhancement projects that will not be undertaken unless the ceiling is even higher than the § 109 price.

The Commission will consider in a separate proceeding whether gas subject to § 104 (gas already dedicated to interstate commerce when the NGPA was enacted) and § 106 (natural gas subject to both interstate and intrastate "rollover" contracts) of the NGPA should be eligible for the incentive price if supply enhancement procedures are necessary to maintain production.

Summary of Benefits

Sectors Affected: Natural gas producers; natural gas users; and the general public.

Large volumes of gas remain in mostly depleted or faulty wells, although it is impossible to estimate the amount. An appropriate incentive price should allow producers to tap reserves of natural gas recoverable only through supply enhancement procedures. The benefits to natural gas users and the general public of increased domestic supplies of natural gas—a clean, environmentally benign fuel—and the possibility of a concomitant reduction in imports of foreign fuels are not precisely quantifiable.

Summary of Costs

Sectors Affected: Natural gas producers; natural gas users; the general public; State jurisdictional agencies; and the Commission.

If the incentive price finally adopted is lower than that necessary to encourage production of reserves recoverable through supply enhancement procedures, these reserves may be left in the ground and therefore, natural gas users and the economy will not benefit from the increased domestic supply. If an incentive price that is higher than necessary is adopted, consumers will pay unjustified prices for the additional gas.

Workload will be increased at the Commission and at the State jurisdictional agencies in order to determine that the supply enhancement work for which the incentive price is claimed has actually been performed and that such work is in fact necessary to produce the gas.

Related Regulations and Actions

Internal: The Commission is considering other categories of gas which may be eligible, as high-cost or high-risk gas, for an incentive price.

External: None.

Active Government Collaboration

None.

Timetable

Final Rule—October 28, 1980.
Rehearing Decision—To be determined.
Regulatory Analysis—The FERC is an independent regulatory agency and is not required to prepare a Regulatory Analysis as prescribed in E.O. 12044. However, the FERC performs essentially the same analysis for rules of major importance and reports the results in the orders issuing NPRMs and final rules.

Available Documents

NPRM—45 FR 51219, August 1, 1980 (Docket No. RM80-50).

Sun Gas Petition for Rulemaking (Docket No. RM80-41).

Final Rule—October 28, 1980.

The comments filed on this proposed rule are available to the public at the Commission's Division of Public Information, Room 1000, 825 N. Capitol Street, N.E., Washington, DC.

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FERC

Procedures Governing Applications for Special Relief Under Sections 104, 106, and 109 of the Natural Gas Policy Act of 1978 (18 CFR Parts 2* and 271*)

Legal Authority

Natural Gas Policy Act of 1978, 15 U.S.C. § 3301 *et seq.;* Department of Energy Organization Act, 42 U.S.C. § 7107 *et seq.;* Natural Gas Act, as amended, 15 U.S.C. § 717 *et seq.;* E.O. 12009, 3 CFR, 1977–78 Comp., p. 142.

Reason for Including This Entry

These proposed regulations would encourage producers of these categories of natural gas to undertake new production or production enhancement projects not otherwise economically feasible. These regulations will cover natural gas production costing millions of dollars annually.

Statement of Problem

The Natural Gas Policy Act of 1978 (NGPA) established a maximum lawful price (MLP) for any first sale of natural gas. The proposed regulations are important in that they would implement the Federal Energy Regulatory Commission's (Commission) authority under the NGPA to set prices higher than the MLP for three categories of gas sales, namely: first sales of gas committed or dedicated to interstate commerce on the day before the date of enactment of the NGPA, first sales of gas under rollover contracts, and first sales of gas not covered by any MLP under any other section of the NGPA. ("First sale" is a term indicating that the sale is subject to the terms of the NGPA and is therefore eligible for NGPA prices. The term does not refer to the first time gas is sold—hence there may be a chain of first sales.) Thus, producers of these categories of natural gas would be encouraged to undertake new production or production enhancement projects not otherwise economically feasible at the MLP specified in the NGPA.

In the past, ceiling prices for producer sales of natural gas were set by the Commission or its predecessor, the Federal Power Commission (FPC), on an area—later a nationwide—basis. These prices were set to cover classes of producers (large or small) and vintage (when the well was drilled or production began). In some instances, however, the ceiling price did not permit a producer to earn a fair profit or, in the extreme case, recover his cost of production. This put the producer face-to-face with two alternatives: continue production at an economic loss, or abandon the well. Neither of these alternatives was in the public interest, as the first affected the producer and would likely discourage further business ventures, and the latter affected the consumer in that it made less gas available. Therefore, regulations called "special relief procedures" were adopted; they allowed producers to apply for prices higher than those set at area or nationwide ceilings.

Passage of the NGPA fundamentally removed the responsibility for establishing ceiling prices from the Commission. The MLP for a particular sale now depends on when the well is drilled, where the gas is produced, and whether it was priced under the earlier practices of the Commission. As part of its general regulatory scheme, however, the NGPA provides that the Commission may set a price higher than that stated in the NGPA for certain types of producer sales; in other words, the Commission may continue to grant "special relief" under the NGPA.

The Commission believes that it is necessary to continue providing producers with the opportunity, in special or unusual situations, to obtain relief from the MLPs. To this end, the Commission has proposed new regulations for granting such relief. The new regulations describe the circumstances under which a producer-seller of natural gas may seek a "special relief" rate, the manner in which the seller may apply for the rate, the process by which the Commission will consider an application, and the cost standards which the Commission will use to determine a special relief rate.

Alternatives Under Consideration

In providing regulations to govern the application for, and granting of special relief under, the NGPA, the Commission must determine which of the various categories of natural gas that are priced under the NGPA will be eligible for the relief, and on what basis it will grant the relief. There are alternatives for both of these questions.

The Commission has the authority to grant special relief for the three above-discussed categories of natural gas sales. It does not, however, have authority to grant special relief for the remaining five categories of natural gas sales defined in the NGPA, namely: new natural gas and certain natural gas produced from the outer continental shelf; natural gas produced from new, onshore production wells; natural gas sold under existing intrastate contracts; certain high-cost natural gas; and stripper well natural gas (wells which produce at very low rates). However, the NGPA could be read to permit a price higher than the MLP for these categories under circumstances which might be considered as warranting "special relief." The Commission is, therefore, considering other rulemaking procedures to encompass some or all of these categories.

Also under consideration is the advisability of an upper limit or "cap" on special relief. The Commission has requested comments on this issue, and a related one: If a "cap" is indeed advisable, what should it be?

One of the more complex problems in establishing a rule for special relief is the criteria by which the Commission should determine a special relief rate. Under the old special relief rules a producer could recover either out-of-pocket expenses or a rate sufficient to provide a fair return on past and future costs, including any extra investment he had to make. The new regulations, while simplifying the standards by providing a formula approach, also distinguish between a producer who must undertake an important investment to make his well economically productive, and one who needs no further investment but needs special relief to cover ongoing operating and maintenance expenses.

The most difficult issues concern the rates to be granted to producers making new investment. The Commission must decide what kinds of investment should be recovered and what the appropriate rate of return on investment should be.

The relative pros and cons of alternative standards are extremely complex. In deciding among them, the Commission must balance the impact of each alternative against the practicalities of producer regulation, the supplies affected, the administrative difficulty (or simplicity) of the regulations, and the intent of the NGPA.

Summary of Benefits

Sectors Affected: The Commission; natural gas production; natural gas pipelines; and natural gas consumers.

This proceeding will directly benefit producer-sellers of natural gas. It will provide the sellers with an opportunity to petition for maximum lawful prices greater than those explicitly set forth under the NGPA. This is important for those sellers who might incur real economic harm or hesitate to undertake new projects because the costs to produce their gas exceeds the MLP they could get for the gas under the NGPA.

In addition, the proceeding will benefit the pipelines that purchase the gas and the ultimate consumers. The benefits will be in the form of added supplies of natural gas—a clean, environmentally benign fuel—which would otherwise never reach the market. These added supplies may permit a reduction in imports of foreign fuels.

Summary of Costs

Sectors Affected: The Commission; natural gas producers and sellers; natural gas pipelines that purchase the gas; and natural gas consumers.

The procedures to allow special relief applications will add to administrative time and costs at the Commission. The number of petitions for special relief that may be filed cannot be determined at this time and will depend upon many variables, including general economic trends and the particulars of individual cases. About 50 to 60 cases per year were administered under the old special relief procedures. This would be a realistic estimate for cases filed under the proposed regulations.

The new procedures of the proposed rule should result in a more economical use of the Commission's time. Thus, administrative costs should be lower than under prior practices. However, about 130 requests for special relief are now pending. These cases, originally filed under the old procedures, form a backlog requiring immediate administrative action under the new procedures.

The granting of a special relief rate means that a producer can receive a higher price for the sale of his gas. This higher price can be passed through to the ultimate consumer. The exact magnitude of this effect is unknown but could well reach millions of dollars annually.

Related Regulations and Actions

Internal: Regulations implementing the Natural Gas Policy Act.

External: None.

Active Government Collaboration

None.

Timetable

Final Rule—December 1980.

Rehearing Decision—To be determined.

Regulatory Analysis—The FERC is an independent regulatory agency and is not required to prepare the Regualtory Analysis prescribed in E.O. 12044. However, the FERC performs essentially the same analysis for rules of major importance and includes the results in the orders issuing NPRMs and final rules.

Available Documents

NPRM—44 FR 49468, August 23, 1979 (Docket No. RM79–67).

Notice Granting Extension of Time to Comment—44 FR 53759, September 17, 1979 (Docket No. RM79–67).

Notice of Public Hearing, issued October 13, 1979 under Docket No. RM79–67.

Notice of Request for Public Comments and Notice of Public Discussion, 45 FR 5321, January 23, 1980 (Docket No. RM79–67).

Transcripts of public hearings and public discussions, and written comments are available at the Commission's Division of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, DC 20426

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FERC

Rate of Return: Electric

Legal Authority

Federal Power Act, 16 U.S.C. §§ 824, 824d, 824e, (Supp. 1979) and 42 U.S.C. 8712(a)(1)(B) (Supp. 1979).

Reason for Including This Entry

The Federal Energy Regulatory Commission has initiated a rulemaking to examine the possibilities for expediting the determination of an appropriate rate of return for electric utilities selling wholesale electric power. This rulemaking could result in a new procedure for setting the rate of return.

Statement of Problem

Electric utilities finance construction in the same manner as other businesses, that is, with a mixture of borrowed and investor funds. In general, the ratepayers do not finance construction or system upgrading. For this reason, the utilities must be allowed a sufficient rate of return on investment so that they can attract investors and raise capital for construction.

Many local electric utilities do not own facilities to generate power and confine their operations to the distribution of electric power bought at wholesale. Under the Federal Power Act of 1935, the Federal Energy Regulatory Commission sets the rates for these wholesale power transactions. The FERC regulates rates charged by 211 electric utilities for wholesale sales of electricity—about 13 percent of total annual sales of electricity in the U.S.

Because many rate increases filed by electric utilities subject to the FERC's jurisdiction are contested by customer utilities, in order to determine an appropriate rate of return, extensive evidence must be taken in a trial-type hearing before an administrative law judge. The rate of return issue is essentially considered anew in each contested rate case.

In a special report to Congress ("Decisional Delay in Wholesale Electric Rate Increase Cases: Causes, Consequences and Possible Remedies," January 23, 1980), FERC Chairman Charles Curtis spoke of the Commission's large and growing electric rate caseload and the length and complexity of electric rate cases. At that time, he suggested that the Commission should work to develop alternative methods for determining the rate of return, perhaps the most time consuming of the elements in a rate case.

Although the capital structure, business organization, and financial condition of electric utilities vary widely, there are enough similarities to suggest that a more general approach to rate of return questions might be possible.

Alternatives Under Consideration

The Commission has three basic alternatives to consider in determining a method for setting the rate of return for electric utilities. First, the Commission could continue the current practice, determining rate of return on a case-by-case basis. This method is geared to individual company requirements, and extremely complex issues of corporate finance and economic market conditions are considered. The advantage of this method is that these requirements can be carefully weighed and a finely tailored result produced. However, this alternative involves a large commitment of FERC resources and is an extremely lengthy process.

As a second alternative, the Commission could develop a general approach for determining an appropriate return. Within this general approach, there are a number of procedural options. The Commission could establish a basic formula for determining the rate of return. Or, the Commission could adopt a specific rate of return or a "zone of reasonableness," a limited range within which a rate of return could be set. This rate or zone of rates would be applicable to all utilities under the FERC's jurisdiction. While the results of a generic approach may not be as precise as those produced by a case-by-case approach, it is possible that the savings in litigation costs may offset any benefits to be gained from such precision.

A third alternative would involve setting specific guidelines for setting rate of return on a case-by-case basis. With this alternative, the Commission could speed up rate cases while retaining the advantages of examining each company's structure and capital requirements.

Summary of Benefits

Sectors Affected: Electric utilities selling power at wholesale; investors in those utilities; electric utilities purchasing power at wholesale; ultimate consumers of electricity; and the Commission.

Shortening the time to decide rate of return issues and simplifying the processes involved could benefit consumers by saving administrative costs in all sectors. Given the Commission's growing caseload, speeding up determination of rate of return, along with other measures to expedite the resolution of rate cases, should allow the Agency to stay abreast of new filings and clear up current backlog.

The Federal Power Act permits the Commission to suspend rate increases for only 5 months before the new rates become effective, while 2 to 3 years are often necessary to evaluate and act on rate cases. This means that the utilities collect rates that may be excessive for long periods of time. Although these rates are collected subject to refund and utilities must make refunds with interest if required, this is nevertheless an inconvenience to consumers and contributes to uncertainty about electric rates. Speeding up the determination of rate of return would reduce this burden on consumers.

Finally, speeding up the determination of rate of return might give investors more confidence in utilities, reduce regulatory risk, and thus lower the costs to utilities of raising capital for construction and system improvements, costs which are passed on to consumers in rates. Speedier case resolution also should assure investor returns more

commensurate with allowed returns, particularly in inflationary periods.

Summary of Costs

Sectors Affected: Electric utilities selling power at wholesale; investors in those utilities; electric utilities purchasing wholesale power; and ultimate consumers of electricity.

Depending on which alternative the Commission selects and how the Commission decides to implement the method selected, there may be costs to one or more of the sectors involved. A high rate of return would result in higher costs to consumers. Conversely, a low rate would reduce rates to consumers. The method selected may also affect investor interest in individual utilities and utilities in general, influencing the cost of capital.

Related Regulations and Actions

None.

Active Government Collaboration

None.

Timetable

NPRM—To be determined.
Final Rule—To be determined.
Rehearing Decision—To be determined.
Regulatory Analysis—The FERC is an independent regulatory agency and is not required to prepare a Regulatory Analysis as prescribed in E.O. 12044. However, the FERC performs essentially the same analysis for rules of major importance and includes the results in the orders issuing NPRMs and final rules.

Available Documents

None.

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FERC

Regulations Governing Applications for Major Unconstructed Projects (18 CFR Part 4*)

Legal Authority

Federal Power Act, 16 U.S.C. § 791a *et seq.*; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et seq.*

Reason for Including This Entry

This rulemaking is important because it simplifies and clarifies licensing requirements and procedures for major projects yet to be constructed, thereby making the development of new sources of hydroelectric power generation—a renewable energy resource with great undeveloped potential—more attractive and efficient.

Statement of Problem

This rulemaking is the third phase of the Federal Energy Regulatory Commission's (FERC) licensing reform program for all projects built for the generation of electric energy by water power that are within the Commission's jurisdiction.

Section 405 of the Public Utility Regulatory Policies Act of 1978 (PURPA) charges the Commission to establish simple licensing procedures for water power projects which are connected with existing dams and have a capacity to generate 15 megawatts (20,000 horsepower) or less of electricity at any one time. The Commission is extending this reform effort to licensing procedures for all water power projects. As a result, this rulemaking proposes licensing reforms which deal with all "major" projects (those with a generating capacity of more than 1.5 megawatts or 2,000 horsepower) (1) for which there is no dam or impoundment (body of water impounded by a dam) at the time of the application, or (2) which would result in a significant increase in the normal surface elevation of an existing impoundment, or (3) which are otherwise determined, pursuant to the Commission's regulations implementing the National Environmental Policy Act of 1969 (NEPA), to have a potentially significant environmental impact.

The current requirements governing licensing of major water power projects are to be found in various sections of the Commission's regulations. An applicant may be required to submit information in as many as 23 different exhibits within each application. Frequently, the existing regulations do not explain in sufficient detail what information applicants must submit. This can result in duplicate filings or deficient applications. The revision of the regulations governing major unconstructed projects where no dam or impoundment has been built will consolidate and simplify the information required of any applicant in order to elicit only that information which is relevant to an informed decision on the merits of the application.

Projects of the magnitude covered by this rulemaking naturally result in more significant environmental disturbances than other, smaller water power projects. The Commission will therefore require any applicant for a major unconstructed project to file an Environmental Report of considerably greater depth and detail than it will require for smaller projects or projects at existing dams. The Commission is also revising its NEPA regulations that set forth the specifications of an Environmental Report for all projects, and is tailoring the requirements for such reports to the type of water power project for which the applicant seeks a license. The need for relatively greater detail concerning such projects also extends to information relating to their structural and financial integrity.

Alternatives Under Consideration

The Commission is not required by PURPA to reform its licensing procedures for hydroelectric projects that are not connected with existing dams. Nevertheless, the FERC has previously reformed hydroelectric licensing procedures outside the scope of PURPA, and this rulemaking accordingly extends to major unconstructed projects the benefits of the simplified licensing program.

The Commission must determine how it will revise the licensing procedures, and decide which of the current reporting requirements to simplify and consolidate. For example, the Commission must determine how extensive the Environmental Report for such projects must be. Because construction of a dam involves flooding land permanently and for the first time and the impacts of extensive construction activity, more environmental detail will be needed to assess the environmental impacts of such a project than is needed for projects where the dam already exists. The Commission will also revise its NEPA reporting requirements to require an Environmental Impact Statement for all such projects.

Summary of Benefits

Sectors Affected: The Commission; State, municipal, and private developers of major unconstructed hydroelectric power projects within the jurisdiction of the Commission; consumers of hydroelectric power; and the general public.

Better licensing procedures should expedite the licensing of water power projects, thus encouraging hydroelectric development. This in turn may help replace costly imported energy supplies with this cheap, renewable energy resource.

Additional hydroelectric facilities will mean that more consumers will have access to hydropower. This may create greater stability in the cost of electricity to consumers. It may even result in lower rates for electric power.

The improved regulations will help conserve the manpower and financial resources of both the Commission and the hydroelectric facility applicants, because the regulations will be more understandable and more reasonable in their requirements. As a result, developers may file fewer deficient applications which require upgrading, and both developers and the Commission may waste less time interpreting and litigating the regulations.

By obtaining more complete environmental data, the improved regulations should also enable the Commission to better fulfill its obligations under NEPA to identify and minimize adverse environmental disturbances. The public will benefit because development of hydropower will be more attractive and adverse environmental impacts will be minimized.

Summary of Costs

Sectors Affected: State, municipal, and private developers of major unconstructed hydroelectric power projects within the jurisdiction of the Commission.

This proposal will require an applicant for a license to construct a major project to file with the Commission a more detailed Environmental Report than is required for smaller projects or for projects at existing dams. The Commission will also require greater specificity regarding the structural and financial integrity of these projects. This will create an additional reporting burden for major project developers. The burden should not discourage them from applying for licenses, however, in light of the significant improvements in the other licensing procedures.

Related Regulations and Actions

Internal: The first phase of the licensing reform program revised the licensing regulations for all "minor" projects (installed capacity of 1.5 megawatts or less) (FERC Order No. 11, 43 FR 40215, September 11, 1978). The second phase revised the regulations for "major" projects (more than 1.5 megawatts of installed capacity) where at least a dam and impoundment are in existence at the time of the application (FERC Order No. 59, 44 FR 67645, November 27, 1979). In conjunction with these reforms, the Commission also revised its procedural regulations governing licenses and preliminary permits for all water power projects (FERC Order No. 54, 44 FR 61328, October 25, 1979).

The Commission proposed new Regulations Implementing the National Environmental Policy Act of 1969 governing the collection, evaluation, and dissemination of environmental information concerning Commission actions (NPRM, 44 FR 50052, August 20, 1979, Docket No. RM79-76).

External: None.

Active Government Collaboration

None.

Timetable

NPRM—November 1980.
Final Rule—To be determined.
Rehearing Decision—To be determined.
Regulatory Analysis—The FERC is an independent regulatory agency and is not required to prepare the Regulatory Analysis prescribed in E.O. 12044. However, the FERC performs essentially the same analysis and includes the results in the orders issuing NPRMs and final rules.

Available Documents

FERC Order No. 11, 43 FR 40215, September 11, 1978.
FERC Order No. 59, 44 FR 67645, November 27, 1979.
FERC Order No. 54, 44 FR 61328, October 25, 1979.
NPRM, 44 FR 50052, August 20, 1979, Docket No. RM79-76.

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FERC

Regulations Implementing Section 110 of the Natural Gas Policy Act of 1978 and Establishing Policy Under the Natural Gas Act (18 CFR Part 271, Subpart K*)

Legal Authority

15 U.S.C. § 3320(a) (Supp. II 1978).

Reason for Including This Entry

These regulations will determine who pays for certain services necessary for natural gas production and transportation and how much may be paid for those services.

This rule involves millions of dollars annually in potential revenues to producers and other sellers of natural gas. The Federal Energy Regulatory Commission (FERC), in providing for collection of production related costs, will establish a workable set of rules for natural gas pricing which may increase deliveries of properly compressed, treated, and processed gas for shipment to ultimate consumers.

Statement of Problem

On December 1, 1978, the Natural Gas Policy Act of 1978 (NGPA) became law. By that law, the Congress established maximum prices for which a producer could sell natural gas. In establishing these prices, the Congress specified that a producer could collect amounts above the maximum lawful prices when the producer incurred particular types of costs, if the Commission approved.

When the NGPA went into effect, the Commission put out interim regulations implementing the Act. Among those regulations were rules defining who could apply to the Commission for production-related costs, what costs could be applied for, and how an application could be made for authorization to collect the add-ons for the costs. The Commission solicited comments on these interim regulations and amended them in July of 1980.

The July 1980 amendments attempted to address three important problems. First, how can the Commission establish a mechanism so that a producer can promptly receive approval to add on to a ceiling price an amount for production-related costs? Second, how can the Commission best respond to the situation in which a pipeline company rather than the producer agrees to incur production-related costs? And third, how can the regulations best be designed to ensure that a producer knows what can be applied for and how to apply?

Alternatives Under Consideration

In implementing the production-related cost section of the NGPA, the Commission has two basic alternatives. It could provide a "simple rule" outlining who can apply, what kinds of production-related costs can be applied for, and how to apply. This was the approach used in the interim regulations first issued to implement the NGPA. That approach was based on a case-by-case determination of cost add-ons and only treated cases in which the producers or other sellers of natural gas incur the production-related costs.

Alternatively, the Commission could establish certain categories of production-related costs that could

automatically be added to a producer's ceiling price and provide for situations when the purchaser, instead of the seller, agrees to incur those costs. In this way, the administration of the program becomes simpler, and both the seller and the purchaser are considered. This was the approach adopted by the Commission in the July 1980 amendments.

In adopting this approach, the Commission decided to proceed step-by-step. First, the regulations were amended to immediately provide that certain minimal types of production-related costs could be automatically added by a producer to a sales price without further administrative action or delay. Second, the two most important types of production-related costs were isolated—costs for gathering natural gas (i.e., collecting it from individual wells and bringing it to a common transporting system) and compressing natural gas (i.e., pressurizing it so that it will move from the gas well to and through a transporting system). An appropriate add-on for these costs will be determined in separate notices of proposed rulemaking so that they too may automatically be added on by sellers.

Third, a policy statement for pipelines that purchase natural gas from producers was issued. This policy describes the types of production-related activities that the Commission will consider for inclusion in the pipeline's rates, further simplifying administrative proceedings.

Finally, FERC would propose a new rule to mark out certain costs that will be considered production costs, as opposed to production-related costs. These costs must therefore be covered by the sales price for the gas, which price cannot exceed the maximum lawful price.

Summary of Benefits

Sectors Affected: Producers and other sellers of natural gas; industry purchasers of natural gas, such as pipelines; and ultimate consumers of natural gas.

All sectors will benefit from a workable and practicable set of rules governing collection of production-related costs.

This rule involves several millions of dollars in potential revenues to producers and other sellers of natural gas. The Commission, in providing for production-related costs, is seeking to establish a workable set of rules for natural gas pricing and to increase deliveries of properly compressed, treated, and processed gas for shipment to consumers.

Summary of Costs

Sectors Affected: Natural gas producers; natural gas purchasers; and natural gas consumers.

Any and every add-on permitted by the Commission to a producer will increase the sale price of natural gas. This price must be paid in all cases by the ultimate consumer of that gas. To the extent that a producer does not get an add-on for a production-related cost, or is delayed in getting the add-on, the producer will incur costs. To the extent that the add-on is permitted, costs will be incurred by natural gas purchasers and, ultimately, paid by natural gas consumers.

The cost involved is sizable but not quantifiable. The amounts involved will be determined by several factors: how many sellers request or receive add-ons; what add-ons are sought; and the amounts of those add-ons. Some measure of the potential impact of the rule can be deduced from the number of producing natural gas wells in the country. There are some 15,000 such wells now in existence, and more being completed every year. There may be production-related costs allowed for most, if not all, of these wells.

Related Regulations and Actions

Internal: Because of the step-by-step process, there are several rulemakings involved. These will include, in addition to the main docket described in this entry, the rulemaking for gathering allowances (to be designated as Docket No. RM80–73), the rulemaking for compression allowances (to be designated as Docket No. RM80–74), and a rulemaking for production costs (to be designated as Docket No. RM80–72). Also, rules considered under Order No. 68, "Final Regulations Under Sections 105 and 106(b) of the Natural Gas Policy Act of 1978," Docket No. RM80–14 (issued January 18, 1980, 45 FR 5678, January 24, 1980), may affect this regulation.

External: None.

Active Government Collaboration

None.

Timetable

Final Rule—Early 1981.
Final Rule Effective—The rule is effective on an interim basis as of July 25, 1980.
Rehearing Decision—To be determined.
Regulatory Analysis—The FERC is an independent regulatory agency and is not required to prepare a Regulatory Analysis as prescribed in E.O. 12044. However, the FERC performs essentially the same analysis for rules of major importance and includes the results in the orders issuing NPRMs and final rules.

Available Documents

The interim regulations on which this proceeding is based were published in the Federal Register of December 1, 1978 (43 FR 56488).

Amendments to interim regulations, Order No. 94, "Regulations Implementing Section 110 of the Natural Gas Policy Act of 1978 and Establishing Policy Under the Natural Gas Act," Docket No. RM80–47 (issued July 25, 1980, 45 FR 53099, August 11, 1980).

Transcripts of hearings and comments on the interim regulations are available and may be obtained from the Commission's Division of Public Information, Room 1000, 825 N. Capitol Street, NE., Washington, DC.

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